Report on the Power Sector

COMMITTEE FOR POWER SECTOR AUDIT, CIRCULAR DEBT RESOLUTION & FUTURE ROADMAP

March, 2020

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COMMITTEE FORMATION AND MEMBERSHIP

1. This report has been prepared in accordance with Notification No. IPP-01(12)/2017 issued by the Ministry of Energy (Power Division) on August 7, 2019, under directions of the Prime Minister of Pakistan, whereby a Committee was constituted to identify and examine the causes of high cost of electricity in the country, including review of private power producers, ways to resolve circular debt and inefficiencies in the transmission and distribution sector, and suggest a future roadmap for the power sector structure (**"the Committee"**). The terms of reference and the composition of the Committee are enclosed at **Annex A.**

2. Any work of this magnitude, without adequate financial and human resources, is bound to suffer oversights given the sheer volume of data which was required to be prepared and analyzed in this short time-period. This is despite the fact that Committee has exercised extreme diligence in checking every figure and its calculation.

3. Without generality of the foregoing, this report may be treated as a recommendatory report without any liability of any sort for any of the Committee members. The report is not an end in itself, rather it is the beginning of a process that needs to be carried forward by officials and institutions exercising executive authority to address the power sector issues aimed at reducing the cost of electricity in the country.

Dated: March 16, 2020

Muhammad Ali – Chairman

Committee Members:

Waseem Mukhtar – MoE (PD)

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M. Noman Akhter – SECP

Salman Rehman – NEPRA

Zubair Mahmood – CPPA

Faiza Yaqub – NPCC

Sajjad Bajwa – FIA

Lt. Col (R) Javad Jehan – ISI

Nauman Khan – Secretary

Co-opted Committee Members:

Muzammil Hussain - Consultant NPCC

Adnan Sattar Khan - NEPRA

M. Imran Ramzan – PPIB

Kaleem Akhtar - NPCC

Abuzar Walayat – Financial Analyst

Ahmad Abdulmoiz - SECP

Hafiz Wajid Wahidi – SECP

Umair Aslam - NPCC

Faheem Baig - NPCC

Syed Ibrahim Ali – Analyst

4. During the course of compiling this report, we were asked how can we engage all the stakeholders in a conducive environment to resolve power sector issues. This is one of the major challenges towards achieving resolution to deep and complex issues of the power sector which is holding back Pakistan's public, economy and industries from achieving their true potential. These issues have resulted in a cost of power which is unsustainable across most economic classes and industrial segments in the country.

5. Power sector policies during the last two decades have allowed exorbitant profits to a select group of investors and encouraged de-industrialization by incentivizing higher capital allocation to a guaranteed and less risky power business. During this time, inefficiencies in the public sector generation and distribution companies were unfortunately tolerated, including by the Federal Government and NEPRA. The reform towards the goal of the ultimate privatization of ex-WAPDA distribution companies has been pending since more than two decades. These companies have been corporatized with independent Boards of Directors, yet operationally this entire distribution sector worth Rs. 1,400 billion is being managed by the Federal Government.

6. During the 30-year period between 1990 and 2019, the dynamics in the global financial markets as well as opportunity cost of investments and returns offered to power sector investors around the world went through many changes. In Pakistan, we remained stagnant in our offering of unjustifiably high guaranteed returns indexed to the US Dollar to investors, presumably in the hope of attracting foreign investment. This is despite the fact that over this period there has been an improvement in the expertise and learning of the local pool of potential investors in the power sector.

7. Consequently, the Federal Government has continued taking responsibility for payment obligations of all costs and investments because of a resistance against transitioning to competitive power markets. This is a classic example of the damage caused to the economy because of partial reform.

8. Today, the country's domestic and international debt levels have reached the point of unsustainability because of which power sector issues require even more urgent redressal. If we do not act soon, we risk economic chaos. Unfortunately, none of the problems have easy solutions. Most require disruptions and losses to certain stakeholders in the short-term if we want to achieve gains in the long-term for all stakeholders. Though it is obvious from this analysis that various mistakes were committed which are part of a natural learning process for policymakers exploring structural changes, it is also obvious that the system and processes were manipulated to the benefit of a select few.

9. In order to find permanent solutions which can benefit the country, a three-pronged approach is needed:

   i. Adjustment or recovery of excess payments made in the past, and shifting away from USD based tariff and take or pay contract provisions;
   ii. Phasing out the Federal Government footprint in commercial aspects of the power sector; and
   iii. Introducing a new power market sector structure which addresses current systemic defects.

10. This will require a revisit of policy deficiencies as well as identification of extraordinary costs charged under the pretext of contractual obligations. Stakeholder engagement will have to be undertaken in order to take corrective financial and policy measures and avoid future excesses. At the same time, the power markets will have to move to a format where buyers and sellers drive efficiencies and costs, in competition with each other. The role of the Federal Government in the control and management of power sector entities will need to be drastically reduced.

11. Each of these steps are mandatory if we are to move forward, and that is where accountability will really matter, accountability of stakeholders who deliberately resist the move out of the status quo.

12. We were fortunate to attract some of the best minds from different institutions for the Committee who were not only patriotic but were also willing to work hard,

disagree strongly and debate each issue passionately. At the same time, we were unable to procure a budget allocation because of which we were limited in obtaining technical and legal support. We have done as best as was possible given our current resources and have recommended areas in the report where the Federal Government ought to separately engage technical and legal experts to look deeper into those issues.

13. Be that as it may, in a sector which is assessed to be losing around Rs. 1000 million daily, a budget allocation of Rs. 22 million to obtain the best international expertise to suggest ways to stop this bleeding of public money was not something we had expected to be denied.

14. This work could not have been completed without the support of Mr. Imran Ahmad Khan, FCA, for providing us with analysts who helped prepare detailed worksheets based on more than 450 financial statements and spent an endless number of hours with our team in CPPA-G. Several other individuals came forward and offered their knowledge, wisdom and support towards this effort. We cannot cover all names here and have tried to highlight the presentations and some of the meetings the committee had in **Annexure B**. The support staff provided by NEECA was also extremely efficient in taking care of logistics and administrative issues.

15. We are grateful to Mr. Imran Khan, the Honorable Prime Minister of Pakistan, for realizing the gravity of the issues in the country's power sector and taking the initiative towards formation of this committee. We would also like to thank Mr. Omar Ayub Khan, Honorable Minister for Energy, Mr. Irfan Ali, Secretary, Power Division, Mr. Aamir Khan, Chairman, SECP, Mr. Tauseef H. Farooqi, Chairman NEPRA, as well as the senior management of CPPA-G, PPIB and NTDC for providing us with some of their best human resources and tremendous support.

Muhammad Ali
Chairman
Committee for Power Sector Audit, Circular Debt Resolution
and Future Roadmap
March 16, 2020

EXECUTIVE SUMMARY

BACKGROUND

16. Pakistan has the highest cost of electricity across all major consumer segments in the region. Given that our exports rely on low value-added products, some of which are heavy on electricity consumption, this high cost of electricity has reduced the competitiveness of our exports, thereby impacting the country's trade deficit and balance of payment.

Table 1 - Regional Comparison of Cost of Electricity[1]

	Cents/kwh	Residential	Commercial	Industrial
1	Pakistan	1.3 – 15.4	12.4 – 15.9	11.8 – 12.5
2	India	4.2 – 11.2	8.4 – 11.9	10.9
3	Bangladesh	4.1 – 12.6	10.8	6.8

17. Currently, the average tariff in the country as well as cost of generation are at their highest levels. It is in this background that the Committee was tasked to conduct a holistic analysis of the causes behind the issues faced by the sector.

18. The Committee divided its review over three parts and proposed an overall action plan consolidating its recommendations in the last section. This is followed by individual IPP-wise reports. Accordingly, this report is divided into five main sections:

    i. Review of Private Power Producers;

    ii. Circular debt and distribution inefficiencies;

    iii. Future roadmap towards a competitive market structure;

    iv. Implementation Plan; and

    v. IPP wise reports.

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[1] Pakistan - Applicable Consumer Tariff for XW-DISCOs in Pakistan; India - https://www.tatapower-ddl.com/Editor UploadedDocuments/Content/Tariff ad English 16x38- 2019.pdf; Bangladesh - https://dpdc.org.bd/article/view/52/Tariff&; Exchange rates: Bloomberg (February 12, 2020)

19. During the course of its work, various sources identified malpractices by private sector generation companies to the Committee, especially with respect to project set-up costs, actual fuel usage being less than invoices submitted to NEPRA, kickbacks in commission on fuel, etc. Since its mandate was restricted to a review of the record made available to the Committee, this Report does not cover such issues. However, a detailed audit has been recommended in order to verify these allegations.

REVIEW OF PRIVATE POWER PRODUCERS

20. A detailed review of the financial statements, relevant public documents, and information provided by the National Electric Power Regulatory Authority [2] (**"NEPRA"**), the Central Power Purchasing Agency[3] (**"CPPA-G"**) and the Private Power Infrastructure Board[4] (**"PPIB"**) was conducted with respect to Independent Power Producers (**"IPPs"**) established under various power policies issued by the Federal Government in 2002, 2006, 2013 and 2015.

21. Despite its best efforts, the Committee was not provided with the break-up of bulk power upfront tariff, including Return on Equity (**"RoE"**) used under the 1994 policy, because of which it was constrained to undertake only a limited review of the IPPs set up under the 1994 Policy.

22. With respect to the relevant financial statements, various adjustments were made to arrive at the true profitability of IPPs, which was lower than the profitability reported. This is because the debt servicing component (principle and interest) is shown as part of revenue in the first ten years of IPPs' operations whereas fixed assets are depreciated over the project life of 25-30 years. Certain other adjustments were also made to cater for distortions due to the accounting policy used.

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[2] https://nepra.org.pk/

[3] www.cppa.gov.pk

[4] http://www.ppib.gov.pk/

Overview of IPP Profitability

23. Historically, IPPs have been offered extremely attractive return formulas, as evident from the following table:

Table 2 - Returns Offered to IPPs set up in Pakistan

Technology	USD IRR
Thermal	
Imported Coal	17.00%
RLNG	16.00%
Local Gas	15.00%
Thar Coal	20.00%
Bagasse	17.00%
Renewable	
Solar/Wind	17.00%-18%
Hydro	17.00%

24. The first IPPs were established under the **1994 policy**, with HUBCO having set up even earlier. We therefore have 20 years of data which allows us to evaluate the impact which our previous policies have had in terms of investment incentives offered to power generation.

25. Under the 1994 Power Policy, 16 out 17 IPPs invested a combined capital of Rs.51.80 billion and have so far earned **profit in excess of Rs.415 billion**, having **taken out dividends in excess of Rs.310 billion**. It needs to be kept in mind that both numbers are understated since they are based on the 275 financial statements available with NEPRA and SECP out of the total 312 statements required.

26. Most of these IPPs had an investment payback period of 2-4 years, **profits generated were as high as 18.26 times the investment and dividends taken out as high as 22 times the investment**. Six companies earned average annual RoE between **60-79%** and four companies earned RoE of around **40%**. These profits are probably unheard of in any other sector, especially with such low level of risk and guaranteed payments by the government.

27. Moving forward, 13 Residual Fuel Oil (**"RFO"**) and gas-based plants with a combined capacity of 2,934 MW were established under the **Power Policy of 2002**. During the last 8-9 years of operations, these companies have so far earned profits of Rs.203 billion against their combined investment of Rs.57.81 billion. Even after adjusting for

debt component to arrive at the true profitability, the companies still earned **Rs.152 billion in profit** and **made dividend payments to the tune of Rs.111 billion**. The individual profitability among these companies also varies, with some showing a much higher profit to investment ratio than others, with the average annual RoE as high as 87%, **profits of around 9 times and dividends up to around 7 times their investment.**

28. Moreover, a review of the profitability of two imported coal-based plants established under the **Power Policy of 2015** shows that one of them has already **recovered 71% of investment in only two years of operations** and the other plant has already **recovered 32% of its investment in the first year**. These plants have been offered USD Internal Rate of Return (**"IRR"**) of 17% which works out to USD RoE of 27%. Due to rupee devaluation against USD in the last two years, their **Rupee RoE today stands at 43%.**

Excess Profitability on Account of Misrepresentations

29. A significant percentage of these profits have been earned on account of:

    a. Misreporting by the generation companies while seeking tariff from NEPRA; and

    b. Misreporting by the generation companies while seeking a tariff adjustment at the time of commercial operations date (**"CoD"**).

30. The NEPRA determined tariff comprises:

    a. Capacity Purchase Price (**"CPP"**), which is the fixed payment, indexed to exchange rate, inflation, interest rates, etc. This is payable regardless of whether the full capacity of the producer is utilized by the power purchaser as long as the capacity remains available to the purchaser;

    b. Energy Purchase Price (**"EPP"**), which is the variable payment based on actual plant dispatch levels mainly fuel, indexed to fuel price. Under the Power Policy 2002 policy, the tariff was based on cost-plus methodology which assumes EPP as a pass-through item depending on prudent expense/usage.

31. In the case of the IPPs established under the Power Policy of 2002, it was found that a major component of excess payments to the IPPs were on account of the actual fuel consumed to generate electricity being less than the payment made by the purchaser in lieu of the use of such electricity. Similarly, the actual O&M expenses incurred by the producer were less than the payment received under this head.

32. Total excess payments made under these and other heads works out to Rs. 64.22 billion during the last nine years with expected future excess payments of Rs. 145.23 billion during the remaining years of operations bringing the **total excess payments of Rs. 209.46 billion** to these plants.

33. Further, while determining tariffs for RFO based IPPs, NEPRA had approved their '*heat rate*"[5] on the basis of information provided by the respective IPPs. The actual heat rate submitted by one of the IPPs which has consistently operated at higher efficiency levels than those submitted to NEPRA is attached at **Annexure 1C**. This is applicable in case of most of the IPPs.

34. Similarly, the O&M component of tariff was based on the estimates provided by the IPPs, which was consistently higher than the actual expenses incurred. This also holds true in case of most of the IPPs.

35. Excess set-up cost of **Rs. 32.46 billion** was allowed to the two coal-based plants due to misrepresentation by sponsors regarding Interest During Construction (**"IDC"**) as well as non-consideration of earlier completion of plants by NEPRA. These plants were completed within 27-29 months, however IDC was allowed for 48 months. As a result, one of the plants, Huaneng Shandong Ruyi (Pak) Energy (**"HSR"**), commonly known as Sahiwal Coal Power Plant, was entitled to an excess RoE of USD 27.30 million in annual payment of return, which is indexed to USD and will be made every year over the entire project life of 30 years. Assuming a 6% annual rupee depreciation the excess payment over the project life works out to a total of **Rs. 291.04 billon**.

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[5] Heat rate is one measure of the efficiency of electrical generators/power plants that convert a fuel into heat and into electricity. The heat rate is the amount of energy used by an electrical generator/power plant to generate one kilowatt-hour (kWh) of electricity https://www.eia.gov/tools/faqs/faq.php?id=107&t=3

36. Under the **2013 Framework for Co-Generation**, eight bagasse-based plants were set up with a total capacity of 254 MW. At the time of tariff determination, the Pakistan Sugar Mills Association reported a Net Annual Plant Capacity factor (**"NAPC"**) of 45% which was used by NEPRA to recover fixed cost in tariff determination. However, the Bagasse power plants under review were operating at higher than 45% NAPC and were therefore being paid for fixed cost, debt payment, etc. which was higher than their actual expense and liability. This has led to excess payments of **Rs. 6.33 billion to the four bagasse-based plants** so far.

Excess Profitability on Account of Overpayment of Tariff Components

37. Under the 2006 Power Policy, 24 wind-based power plants with 1,234 MW capacity and 7 solar based plants with 430 MW capacity were set up. These plants were able to recover their entire cost of debt, interest, O&M, insurance and 17% USD IRR, at a minimum benchmark as determined by NEPRA. Electricity generated beyond this benchmark triggers tariff sharing between the producer and the purchaser, in a pre-determined ratio.

38. Any payment with respect to production over and above the minimum benchmark would lead to an extra payment on account of debt, interest and insurance. Since these companies have achieved CoD relatively recently, it is too early to quantify the real impact of this excess payment, however, if not rectified by NEPRA, this tariff determination methodology is likely to lead to excess payments going forward.

Excess Profitability on Account of Systemic Tariff Issues

39. In addition to excess payments, there were certain oversights which have been noted in all the IPPs which were reviewed, i.e.:

    a. Errors in calculation of the IRR;

    b. Faulty debt component re-payment frequency;

    c. Shortfall in inventory levels; and

    d. Failure to adjust the USD based return allowed by the ECC.

40. At the time of tariff determination, NEPRA calculated IRR for all plants assuming an annual payment of their returns at year end, i.e. 25 payments assumed if project life is 25 years. However, CPPA-G makes these payments to IPPs on a monthly basis with any late payment being subjected to Late Payment Surcharge (**"LPS"**).

41. This mismatch in frequency of payment of return has allowed **6.67% excess payments to 2002 Policy IPPs** (16% IRR instead of the allowed 15%) and **8.1% excess payments to 2006 and 2015 Policy** IPPs in lieu of profits (18.39% IRR instead of the allowed 17%). Assuming that USD appreciates against PKR at an average rate of 6% per annum (actual yearly depreciation was around 6.87% during last 9 years), the excess payment to the 2002, 2006, 2013 and 2015 IPPs under review (6,471 MW) amounts to **Rs. 237.65 billion**, whereas the excess payment to all IPPs except for IPPs installed under 1994 and 1995 Policies (13,156 MW) aggregates to **Rs. 565.88 billion**.

42. A similar systemic error was observed in case of debt payments where NEPRA has assumed quarterly payment of debt to IPPs whereas CPPA-G makes monthly payments for the debt component to IPPs with any late payment being subjected to LPS. This mismatch leads to additional working capital availability for the IPPs. The cost of working capital is already a part of the tariff awarded to the IPPs based on a financing cost of KIBOR + 2%. The impact of this timing difference for 13 IPPs set-up under the 2002 Policy (2,934 MW) aggregates to **Rs. 2.14 billion** for the period under review.

43. Excess payment was also made to certain IPPs set up under the 2002 Policy despite the IPPs having an inventory shortfall. According to NEPRA's tariff determination, the RFO based power plants were required to maintain fuel inventories sufficient to operate the complex for 30 days at 100% load at all times. For this purpose, the IPPs were allowed a cost of working capital component in the tariff. A review of the fuel inventory data for these IPPs revealed that they have largely not maintained their fuel inventory levels, even though these IPPs were receiving payment from CPPA-G based on the predetermined fuel inventory levels, resulting in **excess benefit passed on of Rs.3.6 billion.**

44. Another systemic error observed was conversion of USD based return to PKR based return without taking into consideration the true spirit of the ECC decision taken on May 23, 2007.

45. In 2005, NEPRA had allowed RoE of 15% in PKR based on 10.2% yield on 10-year Pakistan Investment Bonds (PIB) yield as risk free rate, adding a market risk premium of around 4% and asset beta of 1.15, which was then re-levered to the IPPs' proposed capital structure of 75:25. This was used to allow return to all subsequent power generation companies.

46. Currency indexation with USD was not allowed since the PIB rate was used as the risk-free rate which already captures the annual inflation difference and currency depreciation between USD and PKR. However, the Rupee based RoE was later converted to a Rupee based IRR formula, which also included Return on Equity During Construction (**"RoEDC"**), a payment which is a rare phenomenon anywhere else in the world. Eventually, the Economic Coordination Committee of the Cabinet (**"ECC"**), without specifying any specific rate of return, allowed return in USD irrespective of whether the equity being invested was in a local or foreign currency.

47. The PKR based return of 15%, which was based on the PIB yield (10.2%), was converted to 15% USD based return without considering or adjusting for the USD bond yield (which is much lower) in place of PIB. The continued provision of 15% IRR based on PIB, along with USD indexation, amounts to duplication of currency depreciation factor. The impact of this systemic error has so far contributed to excess payments of **Rs. 16.48 billion.**

48. The table below highlights the total excess payments made so far and the payments expected to be made in the future to the IPPs under review.

Table 3 - Overview of Excess Payments on Account of Systemic Errors

Payment	Total Project Life	Remaining Project Life	Already Paid
		Rs. in billion	
Duplication of currency depreciation[6]	4,726.56	-	16.48
Excess fuel and O&M payments	209.46	145.23	64.22
IRR miscalculation	565.88	554.25	11.63
Other Systemic error (debt and plant capacity factor)	12.10	-	12.10
Excess set-up cost allowed	323.50	323.50	-
	5,837.5	**1,022.98**	**104.43**

Way Forward

49. A review of payments to the IPPs leads to three conclusions:

- Their returns have been extremely high;
- Excess payments have been made to power producers because of either misreporting by the producers or regulatory oversight; and
- There is an urgent need to address these as well as issues of current tariff regime to bring down the cost of generation to sustainable levels.

50. The Federal Government has two options for addressing these issues:

Option 1: A negotiated settlement is the preferred option which will require engagement of all stakeholders with a view to arrive at an agreement which ensures that Pakistan's power sector is financially and operationally sustainable in the future.

Option 2: The Federal Government can undertake a forensic audit of all companies with a view to establishing further wrongdoings which were not identifiable under the scope of this Report. This will include:

- Forensic audit of IPPs to verify any over-invoicing in the project cost, fuel usage, misreporting in financial statements, etc.;
- Heat rate audit of the fuel based IPPs;

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[6] Impact for duplication in currency depreciation already paid has been calculated for 2002 Policy (2,934 MW) however, the impact for total project life relates to 2002, 2006 and 2015 policies (13,154 MW).

- Check for possible kickbacks in commissions on fuel supplies; and
- Identify instances where the payment obligations of the power purchaser were materially changed to the benefit of the power producer because of misreporting/misstatements, or any other breach of the relevant regulatory and contractual framework.

51. The Committee had negotiated the terms with an international power consulting firm to obtain data on set-up cost, heat rates, O&M, etc. in countries with similar technology as Pakistan around the same time. However, this exercise could not be completed due to lack of budget approval.

52. Here, it is important to highlight that a major difference was noticed between the set-up cost of a government owned coal-based project initiated through a GENCO, i.e. Jamshoro Power Company Limited and HSR (Sahiwal), an upfront imported coal project of similar technology.

53. Jamshoro's EPC cost is USD 0.66 million per MW compared to the HSR's Capex approved at CoD under upfront tariff of USD 1 million per MW. Though the two costs are not truly comparable as Capex includes non-EPC cost also, a USD 450 million difference in the two costs does raise a red flag about the authenticity of the latter's Capex amount.

54. In order to fix these anomalies of the past, and to bring our cost of generation to sustainable and affordable levels for the country and consumers, the following immediate steps are proposed:

    a. Recover all excess payments made to date.

    b. Put in place a claw back mechanism for sharing efficiency gains in the future subject to verification of set-up costs, periodic heat rate testing, etc.

    c. Shift from USD based returns to PKR based returns.

    The table below highlights the payments to IPPs under the existing arrangement versus payments required in case the shift is made to PKR based IRR at USD-PKR parity of first year after CoD for all plants except 1994 Policy (13,154 MW), leading to savings in excess of **Rs. 4,700 billion** over the project life of these IPPs. On an annual basis, this can lead to saving of at least Rs. 150 billion which will **reduce power tariff in the country by Rs. 1/KWh.**

Table 4 – Savings from shifting to PKR based IRR at USD-PKR Parity of First Year after CoD

Policy	Total RoE expected under existing arrangement	Total RoE expected under first year USD/PKR after COD
	Rs. in billion	
2002 (2,934 MW)	595.43	252.19
2015 (8,253 MW)	**6,514.31**	**2,547.39**
2 Imported coal (2,640 MW)	2,083.82	814.87
Hub + Engro Thar (1,980 MW)	1,562.87	611.15
RLNG (3,633 MW)	2,867.62	1,121.37
RE 2006		
Wind (1,233 MW)	619.26	336.69
Solar (480 MW)	190.86	86.97
Bagasse (254 MW)	73.08	43.14
	7,992.94	**3,266.38**

d. Finish Take or Pay (**"ToP"**) contracts and move to Take and Pay (**"TaP"**).

The table below highlights the annual capacity payments made to 11 plants of 2002 Policy and one IPP of 2015 Policy, and savings in case there were no ToP provisions. This figure is the same as capacity payments made for unutilized capacity.

Table 5 - Savings in case of Shift to TAP

	Name	Capacity Payment (Rs. billion) *	Plant Factor/ Utilization (%) *	Savings due to TaP Rs. billion
1	Liberty Power Tech	4.65	50%	2.35
2	Atlas Power Limited	4.98	36%	3.17
3	Atock Gen Limited	2.86	39%	1.11
4	Nishat Power Limited	4.50	46%	2.45
5	Nishat Chunian Power Limited	4.27	65%	2.45
6	Foundation Power Limited	4.08	88%	0.48
7	Orient Power Limited	4.21	49%	2.14
8	Sapphire Power Limited	4.84	41%	2.83
9	Engro Energy Limited	3.65	82%	0.64
10	UCH II	9.50	94%	0.58
11	Saif Power Limited	4.18	62%	1.59
12	Huaneng Shandong Ruyi - Sahiwal	42.43	80%	8.38
	Total	94.15		28.18

**Actual capacity payment FY 2018-19 with actual plant factor*

55. Next year's CPP projection by CPPA-G is in excess of Rs. 900 billion. With the current excess capacity of 30% in the country, moving to TaP and accounting for demand in growth, the country can easily save at least **Rs. 150-200 billion**, which can lead to **further reduction of Rs. 1/KWh in power tariff.**

56. The report proposes a detailed, policy-wise roadmap for shifting to TaP contracting by continuing to guarantee the debt payment but reducing the guarantee of return payment to 10 years instead of the current 25/30 years. This will also ensure early inclusion of the plants in the competitive power market structure.

57. **In case any of the 1994 or 2002 plants do not agree to shift to TaP,** the government may move towards retirement of these plants in the light of the relevant clauses of the IAs and PPAs. A study of these clauses as well as Tentative Dispatch Plan 2020 (prepared with help of SDDP Software) was undertaken, which analyzed the past six-months and expected future utilizations of the plants. Plants with less than 3% future expected utilization (as per NTDC's estimate) have thereby been identified for the purpose of shut down.

58. Based on this methodology, a total of 9 power plants under the 1994 Policy and 5 power plants under the 2002 Policy have been shortlisted. However, before arriving at a final decision regarding retirement, a technical feasibility in this regard may be carried out to address constraints which may arise due to closure of these plants.

59. A detailed working of the potential saving of **Rs. 739.21 billion** on account of retirement of 11 plants established under the 2002 policy is also given in Section 1 of this report. The data required to perform a similar exercise for the 1994 plants was not available with the Committee, but it can be obtained from IPPs or lenders if the Government decides to retire these plants. Before taking a final decision on this issue, rechecking of termination cost from a financial consulting firm will also be required.

CIRCULAR DEBT

Background

60. Between FY2005 and FY2010, the cost of generation in the country increased by 148% and average tariff by 33% on account of increased international oil price, higher share of furnace oil in electricity generation and PKR depreciation. Circular debt started to emerge in the late 2000s. Successive governments relied on heavy budgetary support and quasi-fiscal financing to eliminate it, however the measures addressed the symptoms and not the root causes.

61. The cumulative budgetary support to the power sector amounted to **Rs. 3,202 billion** from FY2007 to FY2019 comprising:

    i. Rs. 2860 billion as budgetary subsidies; and

    ii. Rs. 342 billion as other liquidity injection.[7]

    Yet, the circular debt stock has continued to grow and increased by PKR 465 billion in FY2019 to around **Rs. 1,600 billion**, leading to total financial loss to the country of **Rs.4,802 billion** during the 13-year period causing **annual loss of around Rs. 370 billion** due to the Power sector inefficiencies.

62. This is especially alarming because, with public indebtedness (public debt/GDP) having increased to 85% in FY2019 from 52% in FY2007, the government's ability to provide fiscal support to the sector is now severely constrained.

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[7] Part of Rs. 480 billion circular debt settlement of Jun-2013. Net lending was Rs. 342 billion.

Circular Debt Stock

63. As per the official definition of the ECC, the circular debt stock represents the overdue payables on CPPA-G's books. However, for the purposes of this report, the circular debt stock includes:

    i. The amount of aggregate overdue payables to power suppliers on CPPA-G's balance sheet; and

    ii. The amount picked up from CPPA-G by the Power Holding Private Limited[8] (**"PHPL"**) by funding it through Federal Government guaranteed borrowing.

64. To reduce the stock level, the following actions are proposed:

    a. Receivables of the DISCOs from the Federal and Provincial Governments, AJ&K and K-Electric (**"KE"**), account for 26% of total DISCO receivables and these should be recovered and used towards reducing the outstanding circular debt stock parked in PHPL in order to reduce the mark-up payments to banks;

    b. The amount recovered as a result of negotiated settlement with IPPs or their forensic audit can be adjusted towards circular debt stock;

    c. Devising a mechanism for sharing the burden of electricity subsidies and the outstanding amount of circular debt between the centre and the provinces;

    d. Introducing additional petroleum levy to meet the cost of circular debt. Taking the benefit of lower international oil prices, with aggregate annual consumption of 20 billion litres of petrol and diesel, a PKR 5 per litre charge would generate PKR 100 billion in additional revenues per year; and

    e. A one-time absorption of circular debt stock into the public debt, ensuring it is linked with quantifiable KPIs and accountability mechanism whereby future savings due to reduced cost of generation and other measures outlined in this report are used to pay back this one-time payment.

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[8] PHPL was established as a special purpose vehicle managed by the Power Division and engaged in primary activity of raising funds to finance the circular debt.

Circular Debt Flow

65. Circular debt flow is the marginal change in outstanding stock of circular debt. It is attributable to:

   a. A high cost of generation;

   b. Transmission and distribution inefficiencies; and

   c. Regulatory and fiscal inefficiencies.

HIGH COST OF GENERATION

66. The high cost of electricity generation is caused by a host of factors, including:

   a. Snowballing capacity payments;

   b. Net Hydel Profit;

   c. Transmission constraints;

   d. Minimum plant factor provision for RLNG based plants;

   e. Gas price anomalies; and

   f. Financing cost of circular debt.

CAPACITY PAYMENTS

67. Historically, high fuel cost was the prime reason behind expensive electricity in Pakistan. Now, snowballing capacity payments are becoming a bigger problem. Since FY2015, about 12,100 MW of net power generation capacities have been added to the NTDC System while another 12,400 MW would be added by FY2025.

68. While the new power generation capacities have helped lower overall fuel cost per unit being based on cheaper fuels than furnace oil, if we compare FY2016 with FY2019, the increase in CPP outweighs this reduction in EPP on per unit basis in both PKR and USD terms. The total CPP amount has in fact increased to Rs. 640 billion (Rs. 5.2/KWh) in FY2019 from Rs. 275 billion (Rs. 2.7/KWh) in FY2016.

69. Further, the front-loaded structure of ToP generation tariffs, coupled with surplus capacity, are contributing to a higher CPP component in the power purchase price ("**PPP**") on a per unit basis. While the terms of the Power Purchase Agreements

(**"PPA"**) with the power producers range from 25 years (renewable) to 40 years (nuclear power plants), their tariffs are based on debt repayments of 10-12 years.

70. This cliff-edge structure of power producers' tariff becomes a bigger problem when large capacity additions are crammed into a relatively short span of time, which is the situation presently confronting Pakistan. Moreover, high interest spreads allowed on project debts of IPPs have enabled lenders to benefit at the expense of electricity consumers. Likewise, the LPS rates are set at KIBOR + 4.5%, while the IPPs' borrowing costs are much lower.

71. To counter these issues the following measures are proposed:

    a. No new power plants be established for the next few years with the exception of conversion of existing wind plants to hybrid wind/solar for system stability and to lower tariff. Plants in the pipeline should either be delayed or reconsidered, and contracts of plants reaching expiry date should not be renewed.

    b. Extending the debt repayment periods of power producers and re-adjusting their tariffs accordingly. A bigger near-term relief in CPP would result from deferral of principal repayments for a period of 3 years.

    c. Reducing the spreads over KIBOR/LIBOR for the long-term project debts.

    d. Lowering the spreads over KIBOR for LPS.

    e. Retirement of older/inefficient GENCOs and IPPs.

    A combination of these measures can immediately help **reduce the annual CPP burden by Rs. 150-200 billion** leading to **a reduction in tariff by Rs. 1/KWh.**

72. Moreover, in order to utilise excess capacity, the following measures are recommended:

    a. Incentivise industry to switch from captive power to grid electricity using competitive tariff offerings and rationalising gas pricing;

    b. Encourage KE to utilise excess capacity from the NTDC grid instead of setting up their own 900 MW RLNG based and 700 MW coal fired plants. In order to achieve this, investment required in NTDC's transmission system will be much lower than the cost of setting up additional plants of 1,600 MW; and

c. Encourage electrification of energy use, e.g. electric vehicles, cooking, air and water heating etc.

NET HYDEL PROFIT

73. With respect to Net Hydel Profit (**"NHP"**), there are major interpretational differences amongst stakeholders about interpretation of Article 161(2) of the Constitution. Despite decades of deliberations, this highly contentious issue still remains unresolved. For example, as per existing practice adopted by NEPRA, NHP for FY2020 would be at Rs. 38.75 billion at Rs. 1.15 per kWh while using KP's version of the 1986 Kazi Committee[9] Methodology (**"KCM"**), the NHP figure works out to be more than Rs. 400 billion per year.

74. Therefore, there is an urgent need to review the situation in light of experience and practices of other countries with significant hydel generation (Brazil, Canada, China, India, etc.), and arriving at a consensus among stakeholders on a sustainable NHP formula which the consumers and the power sector economy can afford.

TRANSMISSION CONSTRAINTS

75. CPPA-G has highlighted that "*...transmission network congestions result in dispatch of expensive generators while cheap generation remains idle owing to said constraints, thus increasing the overall energy Purchase Price for the system*".[10]

76. CPPA-G has projected that the generation on furnace oil would be about 5.2 billion units higher in the scenario with Transmission and Distribution (**"T&D"**) constraints than without it in FY2020. Since fuel cost of oil-based generation is the highest of all types of generation, this increases the aggregate fuel bill which then is passed on to consumers as monthly fuel charges adjustment.

77. At present, the de-rated power generation capacity is 32,767MW, whereas, transformation capacity for 500kV and 220kV is 22,950MVA and 30,746MVA

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[9] In 1986, a committee headed by Mr. A.G.N. Kazi, the then Deputy Chairman Planning Commission, was established to propose a formula for calculation of NHP.

[10] https://nepra.org.pk/Admission%20Notices/2019/09-September/CPPA-G%20Report%20on%20PPP.pdf

respectively. Besides, NTDC also requires investment in installation of grid stations and transmission in order to overcome:

- i. Network constraints at some locations
- ii. Reactive power management problems resulting in voltage variations beyond permissible limits
- iii. Frequency control issues
- iv. Underutilization of NTDC network due to DISCOs constraints

78. The Federal Government should facilitate NTDC in fast tracking the requisite investment in its network to remove these constraints in order to lower the cost of electricity.

MINIMUM PLANT FACTOR FOR RLNG BASED POWER PLANTS

79. The contractual requirements of running the 3 x 1200 RLNG based power plants at minimum 66% annual plant factor entail a higher fuel cost of electricity. The additional cost comes from:

- i. Running these plants out of the merit order; or
- ii. The payment required to be made up to the minimum benchmark in case the plant operates at less than 66% capacity.

80. With a significantly large share of cheaper and must-run guaranteed dispatch EPP plants running on hydro, nuclear, renewable and coal, the probability of the RLNG based plants meeting the 66% plant factor on merit order is relatively low. Further, the ring-fenced pricing mechanism of RLNG and relatively high price of imported LNG[11] make the fuel more expensive than domestic natural gas.

81. Due to a continued slump in international LNG market, the spot prices have dropped to less than USD 3 per MMBTU[12] for March 2020 whereas, because of these legacy contracts, the consumers will be paying more than twice this price[13].

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[11] Pakistan imports 800 MMCFD LNG under term contracts of which 600 MMCFD is priced at 13.37% of Brent.
[12] https://www.thenews.com.pk/print/611962-window-opens-for-pakistan-to-hit-a-low-cost-lng-jackpot
[13] https://psopk.com/en/product-and-services/product-prices/liquefied-natural-gas-lng

82. The preferred option would be price reduction as well as removal of the 66% plant factor requirement which will yield substantial savings. However, this will require renegotiating the terms of the LNG supply contract with Qatar. Additionally, reducing the minimum monthly LNG supply quantities by spreading them over a longer period will also help.

GAS PRICE ANOMALIES

83. There are large variations in the price of natural gas based on its origin and category of consumer, with the consumer price of domestic natural gas generally being much lower than RLNG,[14] which is priced on a ring-fenced basis. In terms of consumption however, the electricity generation sector is RLNG's biggest consumer.

84. The disparities in natural gas prices have multiple adverse effects:

    i. The supply of expensive RLNG to IPPs results in higher EPP for CPPA-G;

    ii. Cheaper domestic natural gas supply to captive power generation incentivises self-generation over grid electricity, which is undesirable given the large capacity surplus. Total power generation by captive power was around 13,400 GWh in FY2019, equivalent to 47% of the grid supply to the industry; and

    iii. The supply of domestic natural gas to some inefficient GENCO units puts them higher on the merit order than they would otherwise be if gas pricing was uniform.

85. RLNG does not become part of the weighted average cost of gas (**"WACOG"**) because the major gas producing provinces claim it to be a violation of Article 158 of the constitution. However, gas usage and pricing are mutually exclusive and perhaps the main reason for the Provincial opposition to combining the cost of RLNG and domestic gas is its potentially negative impact on Gas Development Surcharge (**"GDS"**).[15]

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[14] Pakistan imports 800 MMCFD of LNG under Brent linked term contracts. DES price for 600 MMCFD is 13.37% of Brent while that for 200 MMCFD @ 11.63%.

[15] GDS = Average Selling Price (local gas) – WACOG – Distribution Margin

86. Declining domestic natural gas supplies and potential imports of cheaper LNG by the private sector would in any case constrain the provinces' future GDS revenues and therefore, the Federal Government may consider offering minimum GDS revenues for provinces in return for their consent for making RLNG part of WACOG.

87. The inclusion of RLNG in WACOG would yield significant economic benefits, especially since uniform gas prices for the same category of consumers would help in lowering the cost of electricity generation. It would also enable more efficient natural gas consumption by moving the power plants with higher thermal efficiency up on the merit order, resolve the issue of inefficient gas based old GENCOs, and ease the accumulation of circular debt not only in the power sector but also the one that has started building up in the natural gas sector due to supply of RLNG to domestic consumers.

FINANCING COST OF CIRCULAR DEBT STOCK

88. The financing cost of the outstanding circular debt stock feeds back into an even higher stock of circular debt. Assuming a mark-up rate of 15%, the annual financial cost[16] of the outstanding stock of Rs. 1,800 billion at Dec-2019 should work out to nearly **Rs 270 billion** (around PKR 2.7/KWh based on total units billed in the CPPA-G's record during FY2019).

89. However, the actual cost is less than this amount because of non-payment of mark-up to public sector generators and periodic negotiations of LPS with IPPs.

DISTRIBUTION INEFFICIENCIES

90. For every 100 units of generation in NTDC system during FY 2019:

    i. Around 3 units were lost during transmission; and

    ii. Around 17 units were lost due to T&D inefficiencies at the DISCO level.

91. Therefore, at the transmission and distribution level, effectively only around 80 units were actually sold to consumers. At the billing level, the system is further burdened with a 9% under-recovery. NEPRA allows a loss of 15 units to the DISCOs which

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[16] The amounts on PHPL's books carries mark-up rate of KIBOR + 80bp while the rate of Late Payment Surcharges (LPS) on overdue payables on CPPA-G-G's books is up to KIBOR + 4%.

becomes part of the tariff. This means that the cost of only 2 units lost was borne by the DISCOs themselves.

92. With a total PPP of Rs.1,344 billion, the total cost of the units lost works out to around **Rs. 30 billion**, whereas **Rs. 120 billion** is lost due to under-recoveries.

93. Presentations by operational teams of various DISCOs revealed the following reasons for their technical and administrative losses:

- Over-loading of secondary transmission & distribution system;
- Substandard electrification of villages, new connections being given on political grounds and malpractices of DISCOs' employees;
- Illegal abstraction of electricity through hooks, tampering of meters, etc.;
- Culture of unmetered supply and non-payment in some areas; and
- Financial liabilities on account of disputed arrears pending stays given by the Courts.

94. A bigger issue with DISCOs is under-collection of amounts billed to customers which averaged 91% over the past 7 years (FY2013-FY2019) leading to a cumulative shortfall of **PKR 633 billion**.

95. The receivables of DISCOS from private sector defaulters amounted to P**KR 628 billion** at end of Dec-2019, comprising PKR 525 billion due from running defaulters and PKR 103 billion recoverable from disconnected (permanent) defaulters. More than 87% of the amount recoverable from running defaulters and around 84% from disconnected defaulters is overdue for more than 3 years. Also worrying is the unbridled growth in the amounts due from running defaulters who continue to receive electricity despite non-payment. The continuing increase in these amounts creates doubts about whether they represent disguised T&D losses (excess billing) or genuine billing.

96. In order to reduce these inefficiencies, the following options are recommended:

a. **Transferring management control in a public-private partnership structure:** The private sector is likely to respond better to disruptive technological changes in the energy sector which are leading to paradigm changes in conventional public utility models.

b. **Privatization of commercial activities of DISCOs:** Amendments to the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (**"the NEPRA Act"**) in 2018 segregate the network management function of the DISCOs from the supply function[17]. The latter can therefore be auctioned and handed over to the private sector while the Federal Government can continue to retain the non-risky wire business only.

c. **Breaking down DISCOs into smaller units:** This would entail a de-merger of the ten DISCOs into such number of companies as are suited to the needs of the service territory in question.

d. **Governance changes and balance sheet restructuring:** These are imperative even if the public sector ownership is going to remain unchanged in the near term. DISCOs should have independent boards in the true sense and qualified professional management. Further, the direct involvement of the Federal Government in the affairs of the companies should be minimised.

e. **Closing the loopholes permitting excess billing:** There is a need for transparency by eliminating fictitious billing. Moreover, reputable chartered accountancy firms should be engaged to carry out a detailed scrutiny of receivables from running and permanent defaulters to ascertain their recoverability. Any non-recoverable amounts should be written-off and legal proceedings initiated in terms of section 35A of the NEPRA Act.

f. **Resolving QESCO issues:** A cost and benefit analysis could be done with regard to the provision of cheap off-grid solar power. Technical solutions based around distributed generation and micro-grid systems should be undertaken on fast track basis to curtail QESCO's technical losses. Further, alternative solutions should also be explored for meeting the agricultural and domestic water needs of Balochistan in order to reduce the reliance on tube wells.

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[17] Section 23E(1)

REGULATORY AND FISCAL REGIMES

97. The following factors, in combination, contribute significantly to the build-up of circular debt:

    a. Delays in tariff determinations and notifications due to legal challenges and political considerations;

    b. Under-budgeted tariff subsidies and their slow disbursements; and

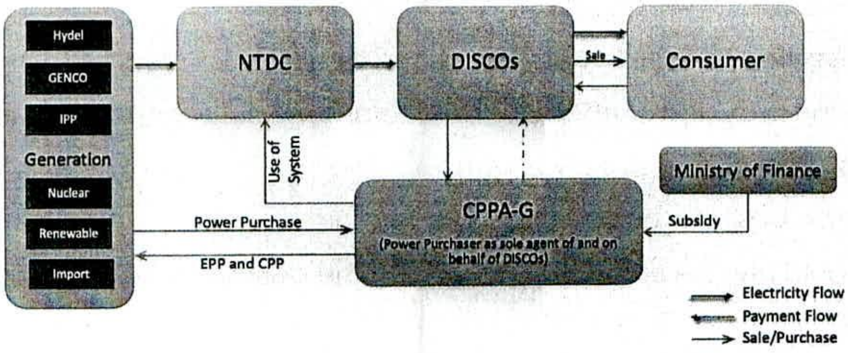
    c. Tax refund claims.

98. Large cross subsidies (especially in the domestic consumer category) and heavy tax incidence are contributing to grid defection by the industrial sector and accelerating solarisation by others having higher electricity usage such as commercial and high-end domestic consumers.

99. There is therefore an urgent need to simplify regulatory processes and enhance Federal Government and NEPRA coordination with a view to limiting the circular debt build-up on these accounts.

FUTURE ROADMAP TO A COMPETITIVE MARKET STRUCTURE

100. Pakistan's power market is currently structured as a 'Single Buyer Model' as shown in the following diagram:



101. Internationally, the single buyer model has been found to create systemic risks and allow lobby pressures to outweigh consumer interests. Similarly, in Pakistan, a failure to transition out of this market structure has led to:

a. Financial risk of the entire sector resting largely with the Federal Government;

b. High cost of electricity;

c. A lack of competition and tolerance for inefficiencies in the system;

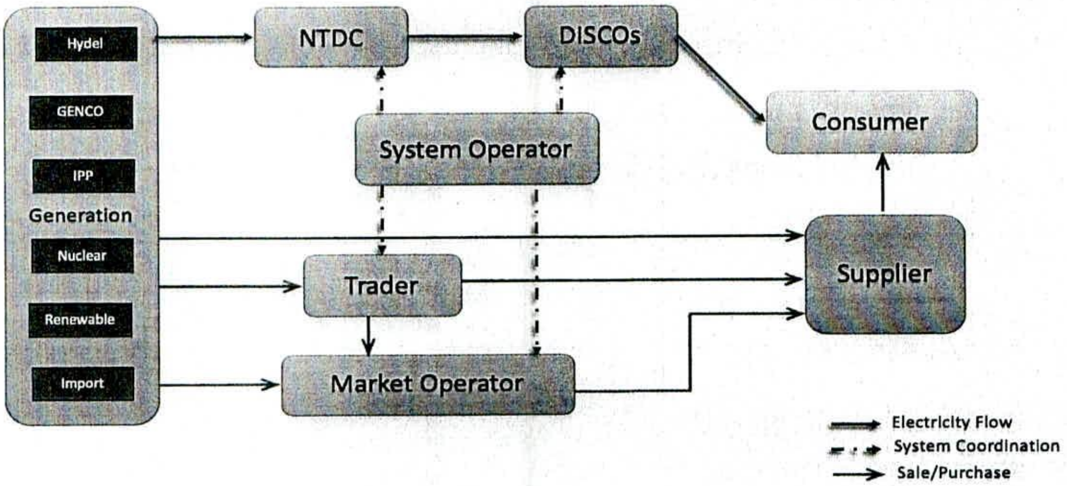
d. Weak demand forecasting causing disproportionate incentives being offered to investors in power generation policies; and

e. Tariffs which do not reflect the true cost of service provision, requiring budgetary support from the Federal Government in the shape of subsidy injection.

102. In contrast, in competitive power markets, power sector service providers are profit driven, hence the market demand and supply dynamics drive efficiency upward and cost of service delivery downward. Further, the financial risks of the sector are spread out over multiple participants in the market.

103. The structural and regulatory reform required to make this transition has historically been resisted in Pakistan. This reluctance could be because of fear of job loss, mistrust between the State and private investors, concerns about loss of control over assets which provide socio-political leverage to the State, etc. and is a main reason why the Federal Government has been largely unsuccessful in driving down the cost of electricity.

104. However, in 2017, the Federal Government moved amendments to the NEPRA Act in Parliament which were approved and notified in April 2018. A main thrust of these amendments was the provision of a regulatory framework within which NEPRA and the Federal Government, in cooperation with the Provincial Governments, could work towards establishment of a multi-buyer competitive electricity market in which the government would neither be a buyer nor a seller. Details of the competitive market related amendments are provided in section 3 of this Report, however, broadly, these amendments envisaged the following new power market structure:



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105. Under the proposed model, the physical infrastructure pertaining to the market, i.e. transmission and distribution lines, can continue to be owned by the Government. But since provision of a distribution and transmission service is the relatively non-risky business of the power markets, it may actually help the Government in raising revenues from use of its power line without worrying about collection and theft.

106. Following through on the legislatively mandated plan would essentially almost eliminate the financial, social and political risks which the Government of Pakistan has been bearing under the existing power policies in field and would also promote much needed efficiency and liquidity in the power sector.

107. In order to give effect to this reform, a new section 14A was introduced in the NEPRA Act which stipulates a:

   i. Broader National Electricity Policy to be approved by the CCI to provide for:

      - Development of efficient and liquid power market design;
      - Integration of national and provincial transmission systems;
      - Reform, improvement and sustainability of the power sector.

   ii. Five-year National Electricity Plan to be developed under the Policy by Federal Government in consultation with the Provincial Governments and after broader public consultation.

108. The development of Policy and Plan in accordance with the statutory procedure is intended to ensure holistic input and buy in of all stakeholders. Also, NEPRA is to provide support and input in the development of the Policy and Plan and to tie in its regulatory objectives and strategy with the approved Policy and Plan.

109. However, despite the passage of almost two years, the relevant rules and regulations to establish the licensing framework have not been developed by the Federal Government or NEPRA although section 50(1) of the NEPRA Act requires the secondary legislative instruments notified before 2018 to be brought in line with the amended NEPRA Act.[18]

110. Further, NEPRA has approved a "*Competitive Trading Bilateral Contract Market Model*" (**"the CTBCM model"**) on 5 December 2019, which was prepared under rules made prior to the passage of the amended NEPRA Act. Section 14A of the NEPRA Act requires the Federal Government to develop "*an efficient and liquid power market design*" along with any matter pertaining to development, reform, improvement and sustainability of the power sector. The approval of such design at the policy level is to be taken from the CCI while the plan is to be made in consultation with the Provincial governments and approved by the Cabinet. Care must also be taken to ensure that the CTBCM Model is in line with the amended NEPRA Act.

111. Therefore, in order to truly transition to competitive electricity markets, it is proposed that:

    a. A full-time committee comprising representatives of the Federal Government, the Provincial Governments and NEPRA be established by the Cabinet with the mandate to:

        a. Develop a draft National Electricity Policy;

        b. Develop the draft five-yearly National Electricity Plans;

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[18] Such as the plan for de-licensing generation under section 14B(5) or the stakeholder consultation for developing the National Electricity Policy or National Electricity Plan.

Such committee should be equipped with financial as well as technical expertise and provided budgetary support to obtain input from local and international experts.

b. Power Division should be restructured to function as a **Technical Ministry** of the Federal Government, staffed with experts in finance, energy economics and law, who can perform various functions critical for moving towards the competitive markets. Some of these are:

   (i) Undertake the functions of PPIB and AEDB with respect to existing PPAs since generation has been de-licensed under the amended NEPRA Act;

   (ii) Coordinate with NEPRA for input in policy and plan as well as development of rules pertaining to the power sector;

   (iii) Coordinate with multilaterals; and

   (iv) Monitor the implementation of the Policy and Plan on behalf of the Federal Government and coordinate with the Provincial Governments thereon.

c. The first proviso of section 50(1) of the NEPRA Act mandates that:

> "...pursuant to the coming into effect of the Regulation of Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2017, **the rules and regulations issued under this Act shall be brought into conformity with the amended provisions of this Act, where so ever required, within a period of one year from the date of coming into effect** of the Regulation of Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2017. "

NEPRA may initiate this exercise at the earliest in order to ensure that the requisite regulatory framework is in place.

IMPLEMENTATION PLAN

112. In order to ensure that the Federal Government can effectively execute the recommendations given in this Report, specific action points by the relevant entity

have been identified. The overall responsibility to monitor progress of this plan is recommended to be passed on to the Power Division, being the authorized arm of the Federal Government. Within the Power Division, either the Minister-in-Charge or Secretary Power may be assigned this responsibility and progress thereon should be reported on a regular basis to the Cabinet.

113. These recommendations are consolidated under three sections, in line with the structure of this Report.

Review of Private Power Producers

Recommendations	Timeline (Months)	Mechanism	Responsibility
Shift from USD to PKR based tariff for all IPPs	3	Change in Policy	Power Division
End Take or Pay arrangements	3	Change in Policy	Power Division
Establishment of Commission for Forensic Evaluation (forensic and legal audit of all IPPs)	1	Cabinet Approval under Pakistan Commissions of Inquiry Act, 2017	Power Division
Review set up costs of IPPs and Lahore Matiari HVDC Transmission	6	Commissions of Inquiry Act, 2017	Commission of Forensic Evaluation
Review risks highlighted in the Report	6	Commissions of Inquiry Act, 2017	Commission of Forensic Evaluation
Recover excess profits made from fuel, O&M, excess setup cost, etc.	3	NEPRA Act	NEPRA
Rectify IRR and debt payment frequency mismatch	3	NEPRA Act	NEPRA
Review IDC and other setup costs of coal IPPs to recalculate RoE	1	NEPRA Act	NEPRA
Review plant capacity benchmarks in renewable IPPs for a more prudent tariff sharing method and recover excess payments made	3	NEPRA Act	NEPRA
Introduce reasonable claw back mechanism in all tariffs (where required)	3	NEPRA Act	NEPRA
Verify fuel inventories of thermal IPPs and adjust outstanding payments against actual levels	Ongoing	Power Purchase Agreement	CPPA-G
Recover excess profits made by generation beyond capacity benchmarks from renewable IPPS	3	NEPRA Act	NEPRA
Consider retirement of GENCOs as well as IPPs established under the 1994 and 2002 Policy	3	Cabinet Approval on recommendations of Committee comprising Power Division, NEPRA and Ministry of Law	Power Division

Circular Debt and Distribution Inefficiencies

Recommendations	Timeline (Months)	Mechanism	Responsibility
Circular debt stock reduction/elimination and reduction of finance cost in line with Committee's recommendations	6	Cabinet approval of measures for one-time reduction with eventual payback from measures implemented by Power Division	Power Division/Finance Division
Debt reprofiling of public sector power plants [WAPDA, PAEC, GENCOs, 4 x 1200 MW RLNG based plants], renewable, CPEC and coal-based projects	3	Negotiate extension of project debt repayment period to 25 years	Power Division
Reduce finance cost on long term project debts, working capital and LPS	3	NEPRA through tariff review	NEPRA
Moratorium on new plants, delay and reconsideration of upcoming plants and non-renewal of plants reaching expiry	1	Cabinet direction to NEPRA, PPIB, AEDB and CPPA-G	Power Division
Novation of PPAs to KE instead of KE setting up new 900 MW RLNG and 700 MW coal-based projects	6	Conducting requisite technical studies for identifying solutions aimed at a) integration of KE and NTDC Systems, b) augmenting supply to KE and c) novation of PPAs of IPPs (coal, nuclear, wind) located in the south.	Power Division/KE
KE to submit timeline for retiring/mothballing old 1200 MW Bin Qasim plant			
Integration of NTDC and KE Systems			
Rollout of a comprehensive plan for electrification of domestic energy use for cooking, space heating, water heating and electronic vehicles for use in public transport	6	Preparation and execution of plans and policies	NEECA/Planning Division
RLNG contract renegotiation and inclusion in WACOG	3	Cabinet approval for re-negotiation and SC opinion on interpretation of Article 158 of the Constitution of Pakistan, 1973	Petroleum Division
Rationalization of natural gas tariff for captive power plants to incentivize their shift to the public grid and for GENCOs to be appropriately utilized in merit order	1	Cabinet Approval	Petroleum Division
Strengthen management of DISCOs, PEPCO, NTDC and PHPL	3	Cabinet Approval	Power Division
Restructure balance sheet of DISCOs	6	Conversion of deferred credit into equity	Power Division
Public private partnership/separation of wire and commercial business and possible breakup of DISCOs into smaller service territories	6	Identification of possible PPP collaborations/initiation of requisite legal actions under NEPRA Act	PPP Authority/ Privatisation Commission
Payment of outstanding subsidies and devising a mechanism for sharing of future subsidies with provinces with at source deductions from amounts transferred under NFC	6	CCI approval on the recommendations of committee comprising Power Division, Finance Division and Law Division	Finance Division
Subcontracting recovery of receivables to private sector	3	NEPRA Act - Supply provisions	Power Division/NEP
Reform QESCO through distributed generation and micro grids	12	Conduct feasibility studies for distributed generation and micro grids (based on indigenous natural gas and renewables)	Power Division
Solutions for QESCO for water supply for irrigation and household consumption	12	Conduct feasibility studies for finding optimal solutions for meeting Balochistan's water needs	Ministry of Water
Rationalization of existing NHP	3	Cabinet approval	Power Division

Future Roadmap – Competitive Power Markets

Recommendation	Timeline (Months)	Mechanism	Responsibility
Establish an inter-provincial committee to finalize draft Policy for approval of CCI and draft 5-year plan for approval of Federal Government	Immediate and ongoing	Section 14A NEPRA Act	Cabinet
Review CTBCM model to ensure it is in line with NEPRA Act	3 months	NEPRA Act - Market provisions	NEPRA
Develop rules to give effect to new provisions of the NEPRA Act regarding power markets: 1. Separate System Operator and Grid 2. Separate Distribution and Supply 3. Establish Electricity Traders	6 months	NEPRA Act	NEPRA/Power Division
Develop regulations to give effect to new provisions of the NEPRA Act and bring old rules in line with amended NEPRA Act	6 months	NEPRA Act	NEPRA

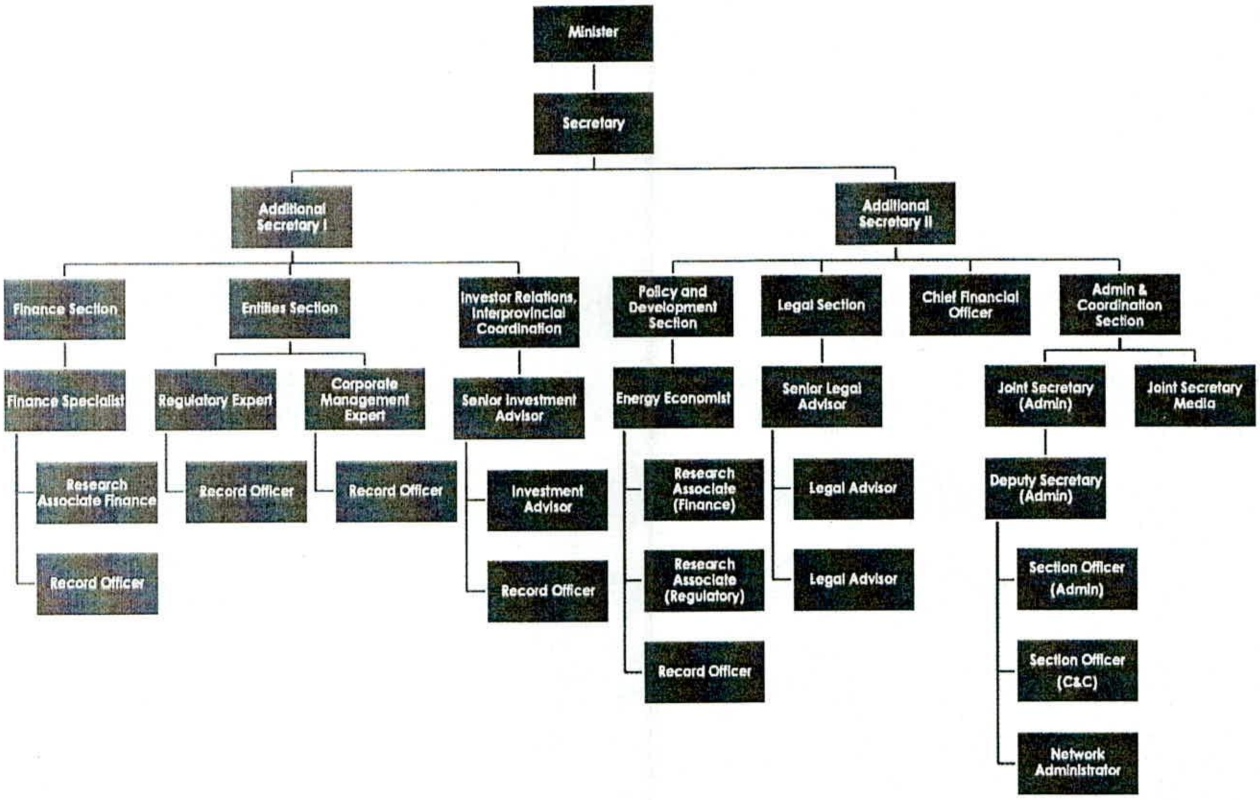
Oversight of Action Plan - Strengthening the Power Division

114. Implementation of these proposals will also require strengthening of the Power Division wherein they will be enabled to hire and develop in-house expertise in different areas.

115. A closer look at the organogram of the Power Division shows that the current organization structure is geared towards an entity-based structure and not function based. This is despite the fact that different kind of specialized knowledge is required to manage the national power policies, plans and sector, which includes expertise in finance, law, energy economics, etc.

116. A restructuring plan was prepared in 2017 by the then Minister for Power, acknowledging the need to strengthen the Division through hiring of professionals having sound knowledge and pertinent experience by offering them market-based compensation packages.

117. The proposed organogram of the 2017 restructuring plan is:



118. This organogram is structured on a functional basis, which will allow decision making based on expert input.

119. Moving forward with a renewed vigor to address the issues faced by the nation's power sector, approving this implementation plan as well as strengthening and restructuring of MoE (Power Division) may be the most important steps in the right direction.

SECTION 1 – REVIEW OF PRIVATE POWER PRODUCERS

INTRODUCTION

120. This section identifies and examines causes of the high cost of electricity in Pakistan, especially in relation to private sector IPPs established under various power polices issued by the Federal Government from time to time. It reviews matters pertaining to tariff determinations, set up costs, operating costs and revenues of the IPPs, and, consequently, quantifies the excess payments made to IPPs on account of various causes, including oversights in tariff determination and variations in tariff sought and tariff granted.

121. The overall impact under each policy has been summarized, organized according to the fuel type used, and a way forward has been proposed. The individual IPP-wise calculations and details are contained in Section 5.

122. There are mainly six Power Policies/frameworks under which 78 IPPs have been commissioned with a gross capacity of 19,418 MW, details of which are tabulated below:

Table 6 - Policy Wise IPP Overview[19]

Policy/Framework	Abbreviation	No. of Projects	Gross Capacity (MW)
Policy Framework and Package of Incentives for Private Sector Power Generation Projects, 1994	1994 Policy	17*	6,031
Policy Framework and Package of Incentives for Private Sector Hydel Power Generation Projects in Pakistan, 1995	1995 Policy	1	84
Policy for Power Generation Projects, 2002	2002 Policy	14	3,081
Policy for Development of Renewable Energy for Power Generation, 2006	RE 2006 Policy	31	1,715
Framework for Power Co-generation 2013 (bagasse/biomass)	Framework 2013	8	254
Power Generation Policy, 2015	2015 Policy	7	8,253
		78	**19,418**

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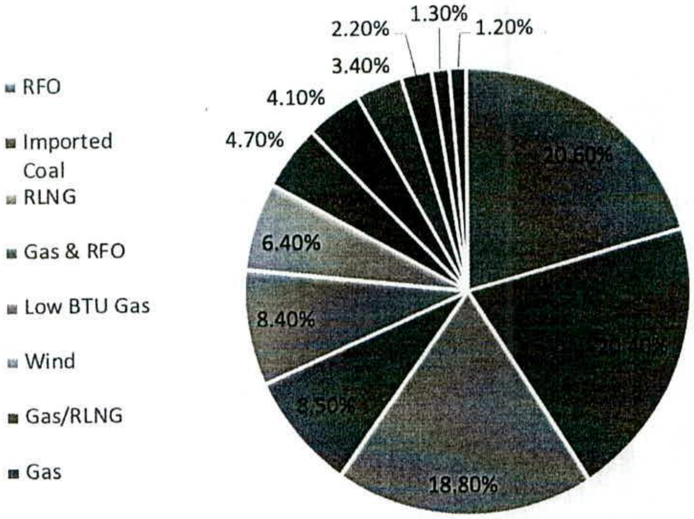
[19] Includes HUCBO though installed prior to 1994 Policy

123. For the above capacity of **19,418 MW**, the energy mix is as follows:

Table 7 -Fuel Mix under all Policies

Fuel Type	Capacity (MW)	% of Total
RFO	3,993	20.6%
Imported Coal	3,960	20.4%
RLNG	3,633	18.8%
Gas & RFO	1,638	8.5%
Low BTU Gas	1,637	8.4%
Wind	1,235	6.4%
Gas/RLNG	908	4.7%
Gas	789	4.1%
Thar coal	660	3.4%
Solar	480	2.2%
Bagasse	254	1.3%
Hydro	231	1.2%
	19,418	**100%**



124. An IPP-wise detail along with sponsor and location information for the IPPs under review, is enclosed as **Annexure 1A.**

THERMAL PLANTS - 2002 POWER POLICY

Salient Features of the 2002 Policy

125. The Federal Government issued the Power Generation Policy 2002[20] (**"2002 Policy"**) in the wake of the unbundling of Water and Power Development Authority's (**"WAPDA"**) power wing and after establishment of National Electric Power Regulatory Authority (**"NEPRA"**) as an independent power sector regulator under the NEPRA Act. The Policy envisages[21]:

- A two-part tariff along with financial and fiscal incentives; and
- A comprehensive security package wherein the Federal Government committed to guarantee all payments, which the power purchaser was obligated to pay to the IPP.

126. The 2002 Policy was amended vide ECC's decisions dated January 4, 2006 and May 22, 2006, to allow income tax exemption to dual-fuel and exclusively oil-fired power generation projects. It was again amended vide ECC's decision dated May 23, 2007, allowing, inter-alia, the Return on Equity to be converted to equivalent US dollars amount at reference exchange rate and adjusted for variations in USD/PKR rates.

ENERGY MIX UNDER THE 2002 POLICY

127. Between March 17, 2009 and November 8, 2017, the following energy mix was inducted under this policy:

Table 8 – Overview of IPPs established under the 2002 Policy

Fuel Type			Number of Plants	Total Capacity (MW)
1.	Thermal	Gas Fired	7	1,724
2.		Residual Fuel Oil	6	1,210
3.	Hydro		1	147
	Total		**14**	**3,081**

128. Details pertaining to ownership, location, commencement of business and remaining life of 2002 Policy plants is contained at **Annexure 1B**

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[20] "PowerPolicy2002.Pdf" (http://www.ppib.gov.pk/PowerPolicy2002.pdf).

[21] Section 6, 7 and 8 of the 2002 Policy

Initial Review of Profitability and Dividends

129. The financial statements and other relevant publicly available information including documents provided by NEPRA, PPIB and CPPA-G were reviewed for the period starting from the CoD till June 30, 2018 or December 31, 2018 depending upon the accounting year end of the IPP under review (**"period under review"**).

130. The financial statements revealed that:

- Almost every IPP set up under the 2002 Policy reported exorbitant profits;
- Large chunks of the reported profits were withdrawn in the form of dividends by the sponsors of IPPs; and
- The investment payback period for most projects was extremely short, ranging between 1-4 years.

NOTE: The following plants could not be reviewed:

- Narowal Energy Limited (220MW, RFO based plant) - non-availability of separate financial statements; and
- Star Hydro Power Ltd. - NEPRA had not finalized the CoD determination till the time of submission of this report.

Table 9 - IPP wise Detail of Profitability and Payback[22]

	Name of Company	Capacity (MW)	Years in Operation	Share Capital/Equity Investment	Profit before Tax	Dividend	Payback Period	Profit/ Capital Ratio	Dividend/ Capital Ratio
				Rs. In Billion					
1.	Attock Gen Ltd.	165	9	3.00	26.76	20.70	1-2 years	8.92	6.90
2.	Liberty Power Tech Ltd.	200	8	5.05	23.97	17.89	2-3 years	4.75	3.54
3.	Nishat Chunian Power Ltd.	200	8	3.67	21.51	12.95	2-3 years	5.86	3.53
4.	Engro PowerGen QadirPur Ltd.	227	9	3.24	17.09	8.70	2-3 years	5.27	2.69
5.	Atlas Power Ltd.	225	8	4.74	18.75	12.68	2-3 Years	3.96	2.68
6.	Nishat Power Ltd.	200	8	3.54	21.61	8.85	2-3 years	6.10	2.50
7.	Saif Power Ltd.	229	9	3.86	16.05	7.61	3-4 Years	4.16	1.97
8.	Foundation Power Company (Daharki) Ltd.	185	8	3.80	8.93	5.36	5-6 years	2.35	1.41
9.	Sapphire Electric Company Ltd.	225	8	4.24	12.54	5.72	5-6 years	2.96	1.35
10.	Orient Power Company Ltd.	229	9	4.45	9.85	3.12	5-6 years	2.21	0.70
11.	Uch-II Power Project	404	5	11.20	20.71	6.59	3-4 Years	1.85	0.59
12.	Halmore Power Generation Company Ltd.	225	7	7.02	5.23	0.87	N/A	0.75	0.12
	Total	2,714		57.81	203.00	111.04			

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[22] Since income tax exemption was available to these IPPs, a nominal amount of tax appeared in the income statements on non-operating revenues. Therefore, for the purposes of consistency, a profit before tax figure has been used.

Table 10 – IPP wise detail of Profit before Tax

	Company Name	COD	Profit Before Tax (Rs. in Billion)								
			2018	2017	2016	2015	2014	2013	2012	2011	2010
1	Attock Gen Ltd.	2009-2018	2.975	2.531	2.462	2.851	3.761	3.745	3.146	2.817	2.473
2	Liberty Power Tech Ltd.	2011-2018	3.545	3.902	3.508	3.691	3.208	2.961	2.157	0.998	-
3	Nishat Chunian Power Ltd.	2010-2018	3.406	2.998	2.756	3.090	2.901	2.713	2.016	1.626	-
4	Engro Energy Ltd.	2010-2018	2.629	2.391	1.788	1.798	2.021	1.458	2.105	1.787	1.112
5	Atlas Power Ltd.	2011-2018	3.180	3.308	3.144	2.290	2.186	1.836	1.443	1.367	-
6	Nishat Power Ltd.	2010-2018	3.211	2.884	2.851	3.117	2.917	2.702	2.035	1.893	-
7	Saif Power Ltd.	2010-2018	3.033	2.592	2.312	2.063	1.988	1.225	1.455	0.779	0.600
8	Foundation Power Company (Daharki) Ltd.	2011-2018	2.093	1.679	1.990	0.942	1.040	0.933	0.365	(0.116)	-
9	Sapphire Electric Company Ltd.	2010-2018	2.243	2.379	2.214	2.052	1.035	1.476	0.923	0.212	-
10	Orient Power Company Ltd.	2011-2018	1.718	1.621	1.763	1.675	1.134	0.812	0.729	0.406	(0.010)
11	Uch-II Power Project	2014-2018	5.615	3.915	4.576	4.726	1.881	-	-	-	-
12	Halmore Power Generation Company Ltd.	2011-2018	1.668	1.007	1.078	1.234	(0.748)	0.591	0.434	(0.029)	-

Table 11 – IPP wise detail of Dividends

	Company Name	COD	Dividend (Rs. in Billion)								
			2018	2107	2016	2015	2014	2013	2012	2011	2010
1	Attock Gen Limited	2009-2018	1.995	2.993	2.993	2.993	2.993	2.494	2.245	1.497	0.499
2	Liberty Power Tech Limited	2011-2018	1.009	10.344	1.766	1.766	1.766	1.236	-	-	-
3	Nishat Chunian Power Limited	2010-2018	0.367	1.102	2.847	2.755	3.122	1.469	0.918	0.367	-
4	Engro PowerGen QadirPur Ltd.	2010-2018	0.971	1.052	0.810	0.810	0.984	2.694	0.453	0.922	-
5	Atlas Power Limited	2011-2018	2.015	2.370	1.778	2.370	2.489	1.659	-	-	-
6	Nishat Power Limited	2010-2018	0.708	1.239	2.213	1.859	1.770	0.708	0.354	-	-
7	Saif Power Limited	2010-2018	1.411	1.372	0.966	1.159	1.353	1.353	-	-	-
8	Foundation Power Company (Daharki) Limited	2011-2018	0.917	0.898	0.898	0.905	0.890	0.856	-	-	-
9	Sapphire Electric Company Limited	2010-2018	1.272	1.272	1.272	0.636	1.272	-	-	-	-
10	Orient Power Company Limited	2011-2018	0.833	0.833	0.625	0.417	0.417	-	-	-	-
11	Uch-II Power Project	2014-2018	1.661	4.930	-	-	-	-	-	-	-
12	Halmore Power Generation Company Limited	2011-2018	-	0.866	-	-	-	-	-	-	-

131. The Guidelines for Determination for Independent Power Producers[23] (**"Guidelines"**) issued by the Federal Government in November 2005 require that tariff should be determined allowing a "reasonable" IRR on equity, and IRR should be equal to the long term interest rates based on auction of ten-year PIB[24] held during the last six months plus a premium to be determined by NEPRA.

132. However, a review of NEPRA's tariff determinations for these 12 IPPs revealed that all of them had been allowed an IRR of 15% with US Dollar indexation, therefore, the profitability numbers were further analyzed to review the basis of the revenue, tariff determination and the payments made by CPPA to IPPs.

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[23] http://www.ppib.gov.pk/tarrif_final.pdf

[24] Which are denominated in Pak Rupees

Detailed Review of Profitability and Dividends - Methodology

133. A review of the NEPRA determined tariff of each IPP included internal workings of NEPRA along with assumptions and calculation of IRR. The component-wise details of EPP and CPP were obtained from CPPA-G. Calculations of tariff components and their payment mechanism was also reviewed based on data provided by CPPA-G and NEPRA. Information regarding late payment surcharge beyond 2018 was not available.

ADJUSTING ACCOUNTING PROFITS

134. Adjustments needed to be made to the accounting profit to arrive at an actual adjusted profit generated from operations, attributable to equity holders. For example, NEPRA allows IPPs to include a major portion of the project cost i.e. the debt servicing component (principle and interest), as revenue. IPPs are allowed to recover this amount in the first 10 years as a part of tariff, so that they can pay off their respective lenders. However, the same principal amount of the debt servicing component is used for financing the project cost and is expensed out through depreciation in the financial statements over the period of project life (25/30 years).

135. Since the principal amount recovered through tariff is recorded as revenue in the financial statements of IPPs, this gives an incorrect picture of the profitability of the company. Therefore, depreciation needs to be added back and debt servicing needs to be excluded from profit.

136. Beside this, various other adjustments have been made to arrive at profit generated from operations, including:

Table 12 - Adjustments made to arrive at Adjusted Profit

	Financial statement item	Rationale
	Profit before tax	
+	Depreciation	Explained in paragraph above
+	Long term finance cost	Assumed to be pertaining to project cost financing and its corresponding debt service payment has also been excluded from accounting profit
+	Short term finance cost	Assumed to be pertaining to working capital financing and its corresponding Cost of working capital has also been excluded from accounting profit
+	Donations	Does not pertain to operation of IPPs
-	Debt service cost	Explained in paragraph above
-	Cost of working capital	Already included in revenue
-	Late payment surcharges	Already included in revenue
-	Capitalized spares	Recognized as an Expense item as assumed to be incurred against O&M payments

137. Details of fuel cost were extracted from financial statements of the respective IPPs on the assumption that raw material consumed comprised of fuel cost only.

138. Similarly, the Operation & Maintenance ("O&M") expenses were calculated from the financial statements by accounting for all relevant expenses and capitalized spares adjusted with depreciation, finance cost, etc. Finally, the fuel cost and O&M expenses as per the financial statements were compared with the fuel cost and O&M payments in Capacity Purchase Price and Energy Purchase Price.

Capacity Purchase Price and Energy Purchase Price

- *CPP is paid on the declared available capacity (regardless of energy generated) and comprises of the following components:*
    - *Fixed O&M - Foreign*
    - *Fixed O&M - Local*
    - *Insurance*
    - *Debt service*
    - *Return on Equity*

Findings of Detailed Review of Profitability and Dividends

EXCESS PROFITABILITY

139. The accounting profit of the twelve IPPs under review is **Rs. 203 billion**, which, after being adjusted in the manner described above (**"Adjusted Profit"**), amounts to **Rs.152.40 billion**. This is still higher than the allowed regulatory profit at 15% USD IRR which works out to Rs. 92.21 billion. After adjusting for the negative impact of Halmore, the difference of **Rs. 64.22 billion** is excess/unexplained profit (**"Excess Profit"** or **"Excess Return"**).

140. Under the cost-plus regime, licensees are allowed the recovery of '*all costs prudently incurred to meet the demonstrated needs of their customers*'[25] and a 'rate of return on the capital investment of each licensees commensurate to that

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[25] Rule 17(3)(i) of the NEPRA (Tariff Standards and Procedure) Rules, 1998

earned by other investments of comparable risk.'[26] Hence, given that these 12 IPPs were given a tariff under the cost plus regime, these standards of tariffs ought to have been applied and the allowed regulatory profit should have equaled the adjusted profit.

141. Out of the Excess Profit, **Rs. 38.96 billion** has already been withdrawn in the form of dividends. The details are given in the table below, organized in the order of highest dividend paid in excess of allowed regulatory profit.

Table 13 - 2002 IPPs: Details of Excess Profits and Dividends

	Project	Years in operation Since CoD	Accounting Profit before tax	Dividend paid	Adjusted Profit	Return on equity allowed	Excess return	Dividend in excess of ROE allowed
			Rs. in Billion					
			a	B	c	d	e = c - d	f = b – d
1	Attock Gen Limited	9	26.76	20.70	19.59	5.78	13.81	14.92
2	Liberty Power tech Limited	8	23.97	17.89	19.84	7.52	12.32	10.37
3	Nishat Chunian Power Limited	8	21.51	12.95	15.82	6.52	9.30	6.43
4	Atlas Power Limited	8	18.75	12.68	12.90	8.12	4.78	4.56
5	Nishat Power Limited	8	21.61	8.85	14.62	6.17	8.45	2.68
6	Uch-II Power (Pvt.) Ltd.	5	20.71	6.59	16.87	9.79	7.08	-
7	Engro PowerGen QadirPur Limited	9	17.09	8.70	11.98	8.95	3.03	-
8	Foundation Power Company Limited	8	8.93	5.36	8.18	6.40	1.78	-
9	Sapphire Electric Power Limited	8	12.54	5.72	9.43	8.08	1.35	-
10	Saif Power Limited	9	16.05	7.61	10.47	9.22	1.25	-
11	Orient Power Company Limited	9	9.85	3.12	8.93	7.87	1.06	-
12	Halmore Power Generation Company Limited	7	5.23	0.87	3.77	7.80	-	-
	Total		**203.00**	**111.04**	**152.40**	**92.21**	**64.22**	**38.96**

142. The data given in the table above formed the basis of:

- The percentage of annual return on equity (**"RoE"**) allowed;
- The percentage of annual RoE based on Adjusted Profit, and
- The difference between the RoE allowed and RoE based on Adjusted Profit, i.e. the annual excess RoE.

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[26] Rule 17(3)(ii) of the NEPRA (Tariff Standards and Procedure) Rules, 1998

Table 14 - Detail of Average Annual Excess RoE

	Project	Years in operation Since CoD	Share capital (Rs. in Billion)	Equity determined as per NEPRA (Rs. in Billion)	Average Annual RoE earned based on determined equity	Average Annual RoE allowed based on determined equity	Average Annual excess RoE earned
1	Attock Gen Limited	9	3.00	2.49	87%	26%	62%
2	Liberty Power tech Limited	8	5.05	4.97	50%	19%	31%
3	Nishat Chunian Limited	8	3.67	4.06	49%	20%	29%
4	Nishat Power Limited	8	3.54	3.91	47%	20%	27%
5	Uch-II Power (Pvt.) Ltd.	5	11.20	12.16	28%	16%	12%
6	Atlas Power Limited	8	4.74	5.39	30%	19%	11%
7	Engro Power Gen QadirPur Limited	9	3.24	4.36	31%	23%	8%
8	Foundation Power Company Limited	8	3.80	4.42	23%	18%	5%
9	Sapphire Electric Power Limited	8	4.24	4.91	24%	21%	3%
10	Saif Power Limited	9	3.86	4.69	25%	22%	3%
11	Orient Power Company Limited	9	4.45	4.92	20%	18%	2%
12	Halmore Power Generation Company Limited	7	7.02	4.42	12%	25%	0%

143. With the exception of Halmore Power Generation Limited, all IPPs under the 2002 Policy, which were reviewed, have earned excess profits during their operations so far. These excess gains mainly arose under the heads of fuel cost and O&M expense, aggregating to **Rs.30.51 billion** and **Rs.20.4 billion,** respectively which means that the IPPs have incurred a lower expense on account of fuel cost and O&M expenses compared to what they have recovered through their respective tariffs.

144. The table below, organized in the order of excess profits, depicts the excess profits earned by each IPP including its break-up into fuel, O&M and other unidentified factors:

Table 15 - Detail of Excess Profits From Fuel Cost and O&M Savings

	Financial Years	Project	Years in operation since CoD	Fuel Saving	O & M Saving	Unidentified saving	Total excessive profit
				Rs. in Billion			
1	2011-2018	Attock Gen Limited	9	8.87	3.81	1.13	13.81
2	2011-2018	Liberty Power tech Limited	8	4.33	5.53	2.46	12.32
3	2011-2018	Nishat Chunian Limited	8	3.02	5.01	1.27	9.30
4	2011-2018	Nishat Power Limited	8	3.36	3.88	1.21	8.45
5	2014-2018	UCH-II	5	2.54	2.70	1.84	7.08
6	2011-2018	Atlas Power Limited	8	1.50	1.70	1.58	4.78
7	2010-2018	Engro PowerGen QadirPur Limited	9	2.32	0.34	0.37	3.03
8	2011-2018	Foundation Power Company (Daharki) Limited	8	(1.68)	1.37	2.08	1.77
9	2011-2018	Sapphire Electric Power Limited	8	2.29	(1.55)	0.61	1.35
10	2010-2018	Saif Power Limited	9	1.97	(0.74)	0.03	1.26
11	2010-2018	Orient Power Company Limited	9	2.00	(1.67)	0.74	1.07
	Total			**30.51**	**20.40**	**13.32**	**64.22**

145. With reference to fuel savings, NEPRA approved 'heat rates' on the basis of information provided by respective IPPs at the time of tariff determination. For example, in the case of Attock Generation Limited (**"AGL"**), an efficiency of 45% net Lower Heating Value (LHV) at 100% load was allowed on the basis of the submitted life cycle heat rate curve (efficiency curve) for 25 years of the project life.

146. The heat rate curve is a function of various assumptions including quality of fuel with sludge of 2%, ageing variation and site-specific condition as detailed in **Annexure 1C**. According to the heat rate curve, efficiency is expected to fluctuate above and below 45% over the life cycle of the project, while its average over the project life is 45%. However, the analysis revealed that all RFO based IPPs, including AGL, operated above 45% since their respective CoDs till the end of the review period.

147. AGL, which has the lowest capacity compared to its policy peers, has earned **Rs. 8.87 billion** on fuel, which contributed to almost **30% of the entire fuel saving of these eleven plants**. The supplier of fuel to AGL is also a company of the Attock Group, which points towards possibility of transfer pricing issues that need to be further probed.

148. With the exception of Foundation Power Dharki, all IPPs have saved on fuel implying higher efficiency levels compared to the heat rate curve submitted.

149. If the same tariff arrangement, fuel savings and other operational factors continue over the remaining project lives of these plants, excess profit of these eleven IPPs over their remaining project life will be **Rs.145.23 billion,** resulting in total excess gains to the tune of **Rs. 209.46 billion**, as tabulated below, organized in the order of highest expected profit for the complete project life:

Table 16 - Future Forecast of Excess Profit if Status Quo is Maintained

	Project	Years in operation	Total Project life	Excess Profit Earned	Expected Excess Profits in rest of project life	Expected Excess Profits for the whole project life
				Rs. in Billion		
		a	b	c	d = c x (b-a)/a	e = c x b/a
1	Liberty Power tech Limited	8	25	12.32	26.18	38.50
2	Attock Gen Limited	9	25	13.81	24.56	38.37
3	Nishat Chunian Limited	8	25	9.30	19.77	29.07
4	Nishat Power Limited	8	25	8.45	17.96	26.42
5	UCH-II	5	25	7.08	28.32	35.40
6	Atlas Power Limited	8	25	4.78	10.15	14.93
7	Engro PowerGen QadirPur Limited	9	25	3.03	5.38	8.41
8	Foundation Power Company (Daharki) Limited	8	25	1.77	3.77	5.54
9	Sapphire Electric Power Limited	8	30	1.35	3.72	5.08
10	Saif Power Limited	9	30	1.26	2.93	4.19
11	Orient Power Company Limited	9	30	1.07	2.49	3.56
	Total			**64.22**	**145.23**	**209.46**

DUPLICATION OF CURRENCY DEPRECIATION IN ROE

150. Orient Power Company Limited was among the first thermal IPPs to be processed under the 2002 Policy. NEPRA allowed RoE of 15% in Pak Rupees in its tariff determination dated June 12, 2005[27]. Till this point in time, the 2002 Policy had not provided any mechanism for determining rate of return for IPPs. NEPRA's determination indicated that a ROE of 14.92% was computed for determining a suitable return, while relying on 10.2% yield of 10-year Pakistan Investment Bond (PIB) as the risk-free rate. Market risk premium was 4% and an asset beta of 1.15 was assumed, which was then re-levered to the IPP's proposed capital structure of 75:25. The RoE of 14.92% was rounded off to 15% and used as a base for allowing return to all subsequent power generation companies. Since PIB rate was used, which already caters to the inflation differential and expected exchange rate fluctuation between PKR and USD, no USD indexation was allowed.

151. In the initial tariff decisions, RoEDC was also not allowed, in line with most international jurisdictions (US, India, etc.). However, subsequent to the 2002 Policy, the Federal Government issued the Guidelines in November 2005, which tilted the incentive package in favor of private power producers:

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[27] https://nepra.org.pk/tariff/Tariff/IPPs/Orient%20Power/2005/LAG-72%20OPCL%20Determination%2012-06-2005.pdf

a. Instead of allowing ROE, an IRR should be allowed which means RoEDC should also be given to the sponsors;[28] and

b. Provide mechanism for determining IRR in place of RoE: *"IRR should be equal to the long-term interest rates based on auction of ten-year PIB held during the last six month plus a premium of "X" determined by NEPRA"*.

152. Since the tariff at that stage was already based in PKR on ten-year PIBs, this adjustment effectively led to an incorporation of RoEDC in the tariff.

153. Subsequently, the ECC through its decision dated May 23, 2007, allowed PKR to USD indexation irrespective of whether the equity invested was in local or foreign currency. The relevant portion of the decision is reproduced as follows;

> *"(vii) The Return on Equity should be allowed in one currency i.e. US dollars. All Return on Equity (for foreign exchange and rupee-based equity) be converted to equivalent US dollars amount at reference exchange rate (as noted in NEPRA's determination) and adjusted for variations in USD/Rs rates as presently being done for return on foreign component of equity."*[29]

154. Accordingly, based on NEPRA's interpretation of this decision, a 15% USD based IRR was allowed for all future investment in electricity generation in the case of projects implemented under the 2002 Policy. This USD indexation policy persisted in all subsequent policies.

155. The interest rate differential between PIB rate and USD interest rate already incorporates any impact of future depreciation of PKR against the US Dollar. Therefore, subsequent to the decision of the ECC, the continued provision of IRR on the basis of PKR based PIB along with USD indexation leads to duplication of premium of PKR depreciation.

156. The impact of this systemic error has so far contributed to excess payments of Rs. 16.48 billion.

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[28] Section 1.4 of the Guidelines

[29] http://www.ppib.gov.pk/PowerPolicy2002.pdf

Table 17- Impact of Duplication of Currency Depreciation in RoE under 2002 Policy

Description	Liberty	Atlas	AGL	NCPL	NPL	Foundation	Orient	Sapphire	Engro	UCH-II	Saif	Total
Capacity	200	225	150	200	200	185	225	225	150	404	225	
Financial Years	2011-19	2010-19	2010-19	2011-19	2011-19	2011-19	2010-19	2010-19	2010-18	2014-19	2010-18	
Number of Years	9	10	10	9	9	9	10	10	9	6	9	
Overpayment w.r.t.Currency Indexation (Rs. Million) allowed by ECC Decision dated May 23, 2007												
RoE	1,350	1,539	1,027	813	1,015	1,432	1,904	1,726	1,045	511	1,285	13,648
RoEDC	208	179	157	225	178	180	382	417	384	147	379	2,837
Total	**1,558**	**1,718**	**1,185**	**1,039**	**1,193**	**1,612**	**2,286**	**2,143**	**1,429**	**658**	**1,664**	**16,485**

OVERSIGHT IN CALCULATION OF INTERNAL RATE OF RETURN (IRR)

157. NEPRA had allowed a return to IPPs based on 15% USD Equity IRR, assuming payment of return on an annual basis. In reality, CPPA-G pays the CPP to IPPs, including RoE, on a monthly basis. Because of this mismatch between the timing of payment envisaged by NEPRA for computation of IRR (annual) versus the actual payments by CPPA-G (monthly), the IRR earned by these IPPs works out to be 16%, which is 1% higher than the 15% IRR allowed by NEPRA.

158. This has led to extra earnings for the eleven IPPs of **Rs. 6.46 billion** during the last 5-9 years of their operations. It is projected that these eleven IPPs will earn an additional **Rs.15.65 billion** excess RoE due to IRR miscalculation. This does not take into consideration the impact of any future depreciation of PKR against USD. Details of total excess payments of **Rs. 22.11 billion** is tabulated below.

Table 18 - Detail of Excess RoE Paid: IRR Miscalculation

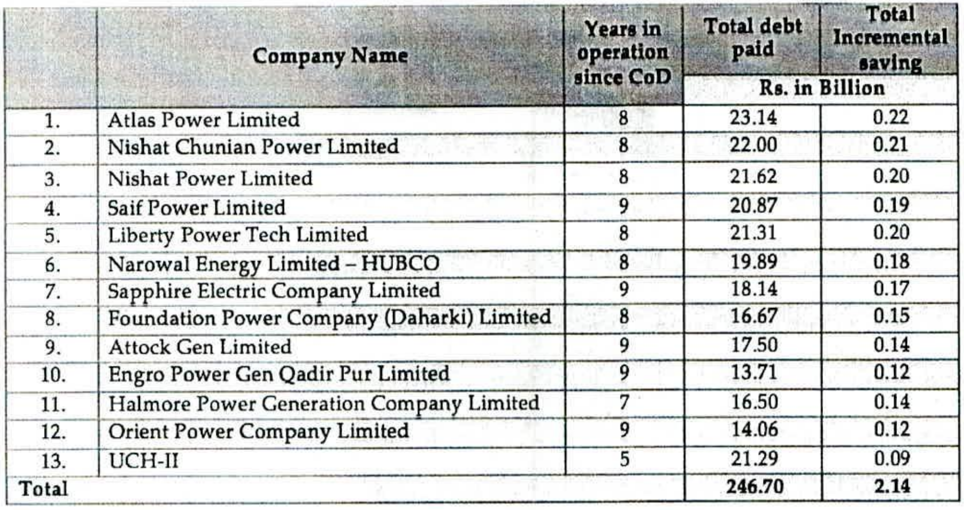
	Project	Years in operation	Project life	Allowed RoE	RoE paid	Excess RoE due to IRR miscalculation paid so far	Excess RoE due to IRR miscalculation to be paid in remaining life	Excess RoE due to IRR miscalculation for the whole project life
				Rs. in Billion				
		a	b	c	d	e = d - c	f = e x (b-a)/a	g = e x b/a
1	UCH-II	5	25	9.17	9.79	0.61	2.45	3.06
2	Halmore Power Generation Company Limited	7	30	7.31	7.80	0.49	1.60	2.09
3	Narowal Energy Limited	8	25	9.47	10.10	0.63	1.34	1.97
4	Saif Power Limited	9	30	8.64	9.22	0.58	1.34	1.92
5	Sapphire Electric Power Limited	8	30	7.57	8.08	0.50	1.39	1.89
6	Orient Power Company Limited	9	30	7.38	7.87	0.49	1.15	1.64
7	Atlas Power Limited	8	25	7.61	8.12	0.51	1.08	1.59
8	Engro PowerGen QadirPur Limited	9	25	8.39	8.95	0.56	0.99	1.55
9	Liberty Power tech Limited	8	25	7.05	7.52	0.47	1.00	1.47
10	Nishat Power Limited	8	25	5.72	6.17	0.45	0.96	1.41
11	Nishat Chunian Limited	8	25	6.11	6.52	0.41	0.87	1.27
12	Foundation Power Company (Daharki) Limited	8	25	6.00	6.40	0.40	0.85	1.25
13	Attock Gen Limited	9	25	5.42	5.78	0.36	0.64	1.00
	Total			**95.85**	**102.31**	**6.46**	**15.65**	**22.11**

MISMATCH IN DEBT REPAYMENT

159. NEPRA had allowed debt repayments to IPPs on a quarterly basis, however, CPPA-G makes payment of CPP to IPPS, including debt repayments, on a monthly basis. This mismatch between the timing of payment envisaged by NEPRA for computation of debt service component (quarterly) versus the actual payments made (monthly), leads to additional working capital availability for the IPPs.

160. It is pertinent to note that the cost of working capital is already a part of the tariff awarded to these IPPs (except UCH-II) based on a financing cost of KIBOR + 2%. Therefore, the impact of this timing difference for all 13 IPPs (2,934 MW) at KIBOR + 2% (KIBOR rate used for UCH-II) aggregates to **Rs. 2.14 billion** for the period under review.

Table 19 - Total Savings: Miscalculation in Debt Component of CPP



	Company Name	**Years in operation since CoD**	**Total debt paid**	**Total Incremental saving**
			Rs. in Billion	
1.	Atlas Power Limited	8	23.14	0.22
2.	Nishat Chunian Power Limited	8	22.00	0.21
3.	Nishat Power Limited	8	21.62	0.20
4.	Saif Power Limited	9	20.87	0.19
5.	Liberty Power Tech Limited	8	21.31	0.20
6.	Narowal Energy Limited – HUBCO	8	19.89	0.18
7.	Sapphire Electric Company Limited	9	18.14	0.17
8.	Foundation Power Company (Daharki) Limited	8	16.67	0.15
9.	Attock Gen Limited	9	17.50	0.14
10.	Engro Power Gen Qadir Pur Limited	9	13.71	0.12
11.	Halmore Power Generation Company Limited	7	16.50	0.14
12.	Orient Power Company Limited	9	14.06	0.12
13.	UCH-II	5	21.29	0.09
Total			**246.70**	**2.14**

SHORTFALL IN INVENTORY LEVELS

161. According to NEPRA's tariff determination, the RFO based power plants were required to maintain fuel inventories sufficient to operate the complex for 30 days at 100% load at all times. For this purpose, the IPPs were allowed a cost of working capital component within the tariff.

162. However, a review of the fuel inventory data for these IPPs revealed that they have largely not maintained their fuel inventory levels, even though these IPPs were receiving payment from CPPA-G based at predetermined fuel inventory levels. Since AGL has a pipeline and fuel levels are not reported, the financial impact of

this shortfall in the remaining five RFO based plants showed extra earning of **Rs.3.63 billion**.

Table 20- Extra Earnings: Shortfall in RFO Inventory Levels

	Project	Years in Operation	Required Quantity (Tons)	Average Quantity Maintained (Tons)	Shortfall in Quantity (Tons)	Fuel Price Determined at COD (Rs. Per ton)	Average Cost of Working Capital (%)	Amount (Rs. in Billion)
			a	b	c = a - b	d	e	f = c x d x e
1.	HUBCO Narowal	8	30,000	9,903	20,097	60,202	11.02%	1.22
2.	Atlas Power Limited	8	30,024	9,212	20,812	45,656	11.05%	0.97
3.	Liberty Power Tech Limited	8	27,570	14,862	12,708	47,962	11.06%	0.64
4.	Nishat Chunian Power Limited	8	27,885	12,910	14,975	42,707	10.68%	0.57
5.	Nishat Power Limited	8	22,662	17,514	5,148	46,364	10.46%	0.22
	Total							**3.63**

2002 Policy: IPP-wise Summary of Excess Payments

163. A summary of the IPP-wise excess earnings so far to 13 plants set-up under the 2002 Policy is tabulated below in order of highest earnings.

Table 21 – 2002 Policy: IPP wise Excess Earnings

	Company Name	Years in operation since COD	Savings Head							
			Fuel savings	O&M	Un-identified	Duplication of currency depreciation	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
			Rs. in Billion							
1	Attock Gen Ltd.	9	8.87	3.81	1.13	1.19	0.36	0.14	-	15.5
2	Liberty Power Tech Ltd.	8	4.33	5.53	2.46	1.56	0.47	0.2	0.64	15.19
3	Nishat Chunian Power Ltd.	8	3.02	5.01	1.27	1.04	0.41	0.21	0.57	11.53
4	Nishat Power Ltd.	8	3.36	3.88	1.21	1.19	0.45	0.2	0.22	10.51
5	UCH-II	5	2.54	2.70	1.84	0.66	0.61	0.09	-	8.44
6	Atlas Power Ltd.	8	1.50	1.70	1.58	1.72	0.51	0.22	0.97	8.2
7	Engro Power Gen QadirPur Ltd.	9	2.32	0.34	0.37	1.43	0.56	0.12	-	5.14
8	Foundation Power Company (Daharki) Ltd.	8	-1.68	1.37	2.08	1.61	0.40	0.15	-	3.93
9	Sapphire Electric Company Ltd.	9	2.29	-1.55	0.61	2.14	0.50	0.17	-	4.16
10	Saif Power Ltd.	9	1.97	-0.74	0.03	1.66	0.58	0.19	-	3.69
11	Orient Power Company Ltd.	9	2.00	-1.67	0.74	2.29	0.49	0.124	-	3.974
12	Narowal Energy Ltd. – HUBCO	8	-	-	-		0.63	0.18	1.22	2.03
13	Halmore Power Generation Company Ltd.	7	-	-	-		0.49	0.14	-	0.63
	Total		30.52	20.38	13.32	16.49	6.46	2.14	3.63	92.924

Note: Only part calculation was possible for Narowal due to unavailability of remaining data

IPPS SET-UP UNDER POWER GENERATION POLICY 1994

Salient features of the 1994 Policy

164. The Federal Government issued the Policy Framework and Package of Incentives for Private Sector Power Generation Projects (**"1994 Policy"**) in March 1994, in the face of an acute power shortage in the country. The Federal Government estimated a conservative 8% demand growth over the next 25 years. The 1994 Policy offered an internationally competitive package of incentives in order to attract overseas and domestic entrepreneurs to invest in the power generation projects in Pakistan.

165. The Federal Government offered a bulk power tariff of US cents 6.5/kWh (Rs. 1.952/kWh) on average for the first 10 years while the levelized tariff worked out to US cents 5.9/kWh (Rs. 1.776/KWh) over the life of the projects (25-30 years).

Tariff for Bulk Purchase

- *The tariff offered was a two-part tariff comprising of CPP and EPP.*
    - *The CPP was to be paid on monthly basis and covered the following:*
        - *Debt servicing*
        - *Fixed operation and maintenance cost*
        - *Insurance expenses*
        - *Return on Equity*
    - *The EPP was to be paid based on actual energy sold to WAPDA/KESC and included fuel price as a pass-through item.*
- *In terms of para 3(B) of Annexure-1 to the 1994 Policy, the tariff was designed in a manner that if fuel cost reduced due to higher thermal efficiency depending on the use of technology, an equivalent increase was to be allowed in the escalable component of the CPP so that the overall tariff remains unchanged.*
- *The tariff offered exchange rate indexations/adjustment, fuel price variation and adjustment due to inflation where applicable.*

Initial Review of Profitability and Dividends

166. Out of 312 financial statements required for analysis of 1994 Policy IPPs, only 275 statements were available with SECP and NEPRA. A summary of the availability status of the relevant financial statements is contained at **Annexure 1D**. Further, in order to determine excess profitability, the allowed RoE tariff component was needed. As 1994 Policy is silent on this, PPIB and the Power Division were requested to provide the detailed financial model on the basis of which the upfront tariff was awarded in 1990s. However, till submission of this report, the requisite information was not available, hence only a limited review of these IPPs could be undertaken.

167. A review of the profits and dividends from the available financial statements for the 1994 Policy Thermal IPPs showed that almost all IPPs reported enormous profits, large chunks of which were withdrawn in the form of dividends. Recovery of equity in the form of dividends was as high as up to 22 times the initial equity injection.

Table 22 - Share Capital with Profit Earned, Dividend Withdrawn, etc.

	Company Name	Years in operation	Share Capital	Profit After Tax	Dividend	Payback Period as per Profitability	Profitability Payback Times	Dividend Payback Times	Average Annual Return	FS Availability
		Since COD	Rs in billion			No of Yrs. from COD	Times		%	
1	Kot Addo Power	23	8.80	160.75	127.71	2-3 Years	18.26	14.51	79%	23/23
2	Tapal Energy (Private) Ltd	23	1.29	17.29	29.38	8-9 Years	13.37	22.72	79%	17/23
3	Gul Ahmad Energy	22	1.68	20.58	15.07	4-5 Years	12.22	8.96	61%	20/22
4	Fauji Kabirwala Power Company	20	1.79	21.86	16.06	2-3 Years	12.22	8.98	64%	19/20
5	UCH-I	18	7.61	88.97	58.07	3-4 Years	11.69	7.63	65%	18/18
6	Kohinoor Energy	23	1.69	15.84	11.40	5-6 Years	9.35	6.73	41%	23/23
7	Habibullah Coastal Power	19	1.72	13.42	7.38	3-4 Years	7.81	4.30	41%	19/19
8	Pak Gen Power Ltd (Formerly AES Pak Gen)	21	3.72	23.81	16.67	2-3 Years	6.40	4.48	43%	15/21
9	Devis Energy Power Ltd	6	0.01	0.05	-	3-4 Years	4.70	-	94%	5/6
10	Lalpir Power	22	3.80	17.13	10.51	2-3 Years	4.51	2.77	38%	12/22
11	Rouche Power Pakistan	20	8.62	30.33	11.98	13-14 Years	3.52	1.39	18%	20/20
12	Altern Energy Ltd	19	3.63	6.52	5.63	16-17 Years	1.80	1.55	9%	19/19
13	Liberty Power Ltd	17	3.53	5.69	-	8-9 Years	1.61	-	9%	17/17
14	Saba Power	19	2.34	0.68	0.26	N/A	0.29	0.11	2%	15/19
15	Japan Power Gen	20	1.56	(7.62)	-	N/A	(4.88)	-	-31%	16/20
16	Southern Electric Power	20	1.37	(11.59)	0.33	N/A	(8.48)	0.24	-50%	17/20

*** NOTE:** The average return has been computed based on the available financial statements. The analysis of HUB Power Company Limited could not be conducted due to unavailability of separate financial statements pertaining to its plants at Lasbela (pre-1994 Policy) and Narowal (2002 Policy) districts.

168. As the profitability, dividends and other details in the above table are based on less than the actual number of financial statements, the actual profitability of companies, in most cases, is likely to be higher than shown above.

169. Additionally, based on information provided by NTDC, Japan Power Generation Company and Southern Electric Power Company have been shut down since 2013 due to a dispute with CPPA-G.

170. Out of 16 IPPs, 6 IPPs have reported average annual return of more than 60% and four IPPs have earned an annual return of around 40%. The Committee is of the view that the matter of excess returns in 1994 needs to be examined in further detail after provision of information pertaining to allowed return on equity by the Ministry of Energy (Power Division).

COAL BASED PLANTS – POWER GENERATION POLICY 2015

Salient Features of the 2015 Policy

171. In 2013, the Cabinet Committee on Energy prepared a roadmap under the multipronged strategy to overcome the energy crisis by 2018. As a result, the Federal Government, in April 2015, issued the Power Generation Policy 2015 (**"2015 Policy"**). Its salient features are as follows:

- It covered not only private and public sector power projects, but also projects based on public-private partnership and projects developed by the public sector with the intention of subsequent divestment.
- It envisaged a two-part, USD indexed tariff comprising of CPP and EPP. The Policy identified EPP to be based on units delivered while CPP was determined to be payable provided the plant was made available for dispatch as per the standards defined in the PPA.
- The Federal Government guaranteed the payment obligations of its power purchaser and that of the provincial/AJK/GB government entities. It also ensured convertibility of Pakistan Rupees into US Dollars and the remittance of foreign exchange to cover necessary payments related to the projects. In order to

mitigate the exchange rate variation risk, specified adjustments for exchange rate variations were also provided within the Policy.

- It provided exemption of income taxes, import of equipment not locally manufactured at a concessionary customs duty rate of 5%, and repatriation of equity along with dividends. Further, NEPRA allowed a USD equity IRR of up to 20% in the tariff.
- The PPIB and relevant public sector departments in provinces, Azad Jammu & Kashmir ("AJK") and Gilgit Baltistan ("GB") were mandated to implement the policy by providing a one-window facility to prospective project sponsors.

172. The energy mix which was set-up under the 2015 policy is as follows:

Table 23 - Energy Mix under the 2015 Policy

	Project	**Technology**	**MW**	
1	CIHC Pak Power Company Limited	Imported Coal	330	39%
2	China Power Hub Generation Company		1,320	
3	Port Qasim Electric Power Company		1,320	
4	Huaneng Shandong Ruyi		1,320	
5	Grange Power Limited		150	
6	KAPCO Energy		660	
7	Datang Pakistan		700	
		Sub-total	**5,800**	
8	Punjab Thermal Power Generation	RLNG	1,263	33%
9	National Power Parks - Balloki		1,223	
10	National Power Parks - Haveli Bahadur Shah		1,231	
11	Quaid-e-Azam Thermal		1,180	
		Sub-total	**4,897**	
12	Lucky Electric Power	Thar Coal	660	24%
13	Siddiqsons Energy Power		330	
14	Engro Powergen Thar		660	
15	ThalNova Power Thar		330	
16	Shanghai Electric Power		1,220	
17	Thar Energy Limited (HUB)		330	
		Sub-total	**3,530**	
18	Riali 2 Hydro Power Project	Hydro	7	4%
19	Kathai 2 Hydro Power Project		8	
20	Athmuqam Hydro Power Project		450	
21	Turtonas - Uzghor Hydro Power Project		82	
		Sub-total	**547**	
		Total	**14,774**	100%

173. The following companies have achieved CoD under the 2015 Policy:

Table 24 - IPPs under the 2015 Policy

	Name of IPP	Gross Capacity (MW)	Fuel	CoD Date
1	Huaneng Shandong Ruyi (Pak) Energy Pvt. Ltd.	1320	Imported coal	28.10.2017
2	Port Qasim Electric Power Company Pvt. Ltd.	1320	Imported coal	25.4.2018
3	China Power Hub Generation Company Pvt. Ltd.	1320	Imported coal	19.9.2019
4	National Power Parks Management Company Pvt. Ltd. (Haveli Bahadur Shah Power Project)	1230	RLNG	29.7.2018
5	Quaid-e-Azam Thermal Power Pvt. Ltd.	1180	RLNG	20.5.2018
6	National Power Parks Management Company Pvt. Ltd. (Balloki Power Project)	1223	RLNG	29.7.2018
7	Engro Powergen Thar (Private) Limited	660	Local coal	10.7.2019
	Total	**8,253**		

174. In case of China Power Hub Generation Company and Engro Powergen Thar (Private) Limited, the CoD adjusted determination of tariffs have not been issued by NEPRA till the time of preparation of this report.

175. Further, two out of three RLNG based projects, namely Haveli Bahadur Shah Power Project and Balloki Power Project, are owned by Federal Government, whereas Quaid-e-Azam Thermal Power Pvt. Ltd. (Bhikki) is owned by the Government of Punjab.

176. Therefore, analysis of the two imported coal-based power projects namely Huaneng Shandong Ruyi (Pak) Energy – Sahiwal (**"HSR"**) and Port Qasim Electric Power Company (**"PQEPCL"**) was undertaken.

DETERMINATION OF COAL UPFRONT TARIFF

177. NEPRA, after various deliberations and consultations with the stakeholders, finalized the following tariffs along with corresponding efficiencies and project costs

Table 25 - NEPRA Determined Tariff by Thermal Efficiency

Levelized tariff	Imported Coal		Local Coal	
	Foreign Financing Cents/kWh	Local Financing Cents/kWh	Foreign Financing Cents/kWh	Local Financing Cents/kWh
220 MW	8.6417	9.6774	8.2537	9.2978
350 MW	8.5353	9.624	8.1784	9.2759
660 MW	8.3601	9.5422	8.0116	9.21
1099 MW	8.0189	9.1198	7.6738	8.7897
Thermal Efficiencies (Net LHV)	220 MW	350 MW	660 MW	1099 MW
Imported / local Coal	37.00%	39.00%	39.00%	40.00%

Table 26 - NEPRA Determined Project Cost for Imported Coal

Description	220MW		350MW		660MW		1099MW	
	F. Fin.	L. Fin.	F. Fin.	L. Fin.	F. Fin.	L. Fin.	F. Fin.	L. Fin.
	USD in million							
Capital Cost	271.8	271.8	455.0	455.0	767.9	767.9	1,191.7	1,191.7
Custom Duties & Cess	10.8	10.8	18.1	18.1	30.5	30.5	47.3	47.3
Sub-Total	**282.6**	**282.6**	**473.0**	**473.0**	**798.4**	**798.4**	**1,239.0**	**1,239.0**
Financial Charges:								
Financing Fees & Charges	7.4	7.4	12.4	12.4	21.0	21.0	32.5	32.5
Sino sure Fee	22.2	-	37.1	-	63.9	-	99.2	-
IDC	19.3	67.0	32.2	112.1	72.8	261.6	113.0	405.9
Sub-Total	**48.8**	**74.4**	**81.7**	**124.5**	**157.7**	**282.5**	**244.7**	**438.5**
Total	**331.4**	**357.0**	**554.8**	**597.5**	**956.1**	**1,080.9**	**1,483.7**	**1,677.5**

Detailed Review of Profitability - Methodology

178. Since HSR and PQEPCL have only been operational for 1-2 years, insufficient time has passed to review the profitability of these projects. Therefore, the tariff determinations of these projects including the components of set up cost were reviewed.

179. Due to the budget request for hiring international consultants not being approved, it was not possible to undertake third-party comparisons between actual project costs reported by these projects and project costs established internationally for similar technologies. Alternatively, various components of tariff were reviewed with the objective of ascertaining their reasonableness and basis of calculation.

180. The total project costs of the two IPPs as determined by NEPRA were compared with the project cost capitalized in their financial statements.

Overview of Findings

EXCESS ALLOWANCE OF RS. 32.46 BILLION ON ACCOUNT OF SET-UP COST

181. A comparison of the total project cost of the two IPPs as determined by NEPRA versus the amounts reported in their financial statements showed that excess project cost was allowed to the two IPPs to the tune of **Rs. 32.46 billion** with the following breakdown:

Table 27 – Excess Setup Cost allowed to IPPs under 2015 Policy

Coal Project	Excess Set-up Cost (Rs. Billion)
HSR	13.16
PQEPCL	19.30
Total	**32.46**

182. The main component of this excess cost was the financing cost including IDC. In the case of HSR, at the time of CoD, the IPP had requested an IDC of USD 197.34 million. However, NEPRA allowed IDC of Rs. 17.56 billion (USD 167.91 million), whereas as per the financial statements of HSR, the IPP actually incurred an IDC of Rs. 6.71 billion, leading to an excess allowance of **Rs. 10.85 billion** in set-up costs (**USD 103.77 million** at CoD exchange rate).

183. Similarly, PQEPCL was allowed Rs. 24.84 billion (USD 234.91 million) in finance cost (including IDC, Sinosure fee, lenders fee, etc.) whereas it actually incurred Rs. 12.53 billion (USD 112.79 million) on this account giving rise to an excess allowance of **Rs. 12.31 billion** (**USD 122.13 million**) in set-up cost. The aforementioned excess allowances were due to the following reasons:

    i. Actual construction period of 27 – 29 months being less than the 48 months' time assumed by NEPRA in its determinations; and

    ii. Misrepresentation by the sponsors of both IPPs as interest payments against these borrowings were lower than those reported to NEPRA.

EXCESS RETURN PAYMENT OF USD 27.40 MILLION PER ANNUM TO HSR

184. NEPRA allowed total project cost of USD 1,782.31 million and equity of USD 361.6 million to HSR at the time of CoD tariff determination. However, after adjusting for excess allowance in setup cost (mainly IDC) as explained in the previous paragraphs, the adjusted project cost and equity work out to USD 1,678.54 million and USD 340.57 million respectively.

185. Based on this adjusted equity amount, HSR was entitled to USD 70.90 million per year as RoE, however, HSR has been allowed USD 98.30 million by NEPRA, meaning an excess of **USD 27.40 million** in annual return payments will be made to HSR over the project life of 30 years.

186. Since the project has recently started and the RoE is indexed with USD, assuming that USD appreciates against PKR at an average rate of 6% per annum, the excess payment on this account aggregates to a total of **Rs. 291.04 billon** over the next 30 years.

187. In case of PQEPCL, NEPRA corrected the error of construction period and assumed actual construction period to compute return during the construction period.

IRR MISCALCULATION – EXCESS PAYMENT OF RS. 160 BILLION TO TWO PLANTS

188. NEPRA has allowed HSR and PQEPCL a 17% USD based equity IRR, assuming payment of return on an annual basis as against actual payment by CPPA-G of CPP, including RoE, on monthly basis. Because of this mismatch, the IRR earned by these two IPPs works out to be higher than the IRR allowed by NEPRA, i.e. 18.39% return instead of 17% return.

189. This excess 1.39% IRR translates to around **Rs. 1 billion** per year extra payment to each IPP at the current USD/PKR Exchange rate. Assuming that USD appreciates against PKR at an average rate of 6% per annum, the excess payment on account of IRR would amount to **Rs. 72.5 billion** in case of HSR and **Rs. 87.6 billion** in case of PQEPCL, aggregating to **Rs. 160.14 billion** over the entire project life of these two IPPs.

190. Expected overpayment to RLNG plants, which are in the public sector will also need to be rectified by NEPRA before their privatization.

MISMATCH IN DEBT REPAYMENT

191. As discussed in detail under the section on 2002 Policy IPPs, the mismatch between the timing of debt payment envisaged by NEPRA for computation of debt service component (quarterly) versus the actual payments made by CPPA-G (monthly) leads to additional working capital availability for the IPPs which eventually leads to additional profitability.

192. Since the projects under 2015 Policy have recently achieved CoD and major debt repayments will be made in the future, due to unknown assumption, it was not possible to project the future impact of this mismatch.

2015 POLICY - IPP-WISE SUMMARY OF EXCESS PAYMENTS

193. A summary of the IPP-wise excess earnings is tabulated below.

Table 28 - 2015 Policy: Excess Payments

Coal Project	Excess Set-up Cost	Excess Return due to excess set up cost (30 years)	Excess Return due to miscalculation of IRR (30 years)	Total excess return/ overpayments
	Rs. in billion			
HSR	13.16	291.04	72.51	376.71
PQEPCL	19.30		87.63	106.93
Total	**32.46**	**291.04**	**160.14**	**483.64**

RENEWABLE POWER PLANTS – 2006 AND 2013 POLICIES

2006 Policy for Development of Renewable Energy 2006

SALIENT FEATURES OF THE POLICY

194. In 2006, the Federal Government issued Pakistan's first Policy for Development of Renewable Energy for Power Generation[30] (**"2006 Policy"**) with short-term, medium-term and long-term targets[31] to exploit:

- Small hydro (up to 50 MW) technologies;
- Solar photovoltaic (PV) and thermal energy for power generation; and
- Wind power generation.

195. All other RE technologies were excluded from this policy. The policy recognized a minimum 9,700 MW as the medium-term target for deployment of renewable energy (**"RE"**) technologies by the year 2030[32].

196. The purchase of electricity by Federal Government from qualifying RE projects was made mandatory while provisions of electricity wheeling and net metering were also made available.[33] Further, RE projects identified under the policy for sale of all power to the grid system were allowed through either Build, Own and Operate (**"BOO"**) or

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[30] Available at http://www.aedb.org/Documents/Policy/REpolicy.pdf

[31] Paras 7 and 8 of the 2006 Policy

[32] Para 5 of the 2006 Policy

[33] Para 8.2 of the 2006 Policy

Build, Own, Operate and Transfer (**"BOOT"**) models which shall be valid for a period of not less than 20 years.

197. The policy envisaged a tariff based on per-unit rate (Rs./KWh) as the policy acknowledged it is difficult for RE IPPs to guarantee capacity availability. Further, in the case of hydro projects, a water use charge of Rs. 0.15/kWh was also fixed within the 2006 Policy, which was to be paid by the IPP to the provincial/AJK/Northern Area governments.

198. The risk of variability of wind speed and water flow was envisaged to be borne by the power purchaser. It was conceived that for each project location identified under the policy, benchmark electricity production levels based on mean availability of wind and water flow on monthly basis were to be determined and revenues corresponding to this benchmark were ensured to the IPPs provided that reduction in electricity production was not due to the IPP's fault.

199. This is similar to capacity payment up to a certain minimum benchmark, irrespective of power supply. For production beyond the benchmark, power producer was to be paid a certain percentage of tariff, which served as bonus payments for the IPPs so as to incentivize investment in renewable technologies.

200. Other incentives included exemption from income tax, repatriation of equity and dividends, and provision to raise local and foreign financing.

Wind-based IPPs set-up under 2006 Policy

201. The tariff wise details of Wind IPPs which have achieved CoD under the 2006 RE Policy is as follows:

Table 29 – Wind IPPs under 2006 Policy

Tariff regime	No. of IPPs	Capacity MW
Cost plus tariff	7	354.9
Upfront 2013	8	433.6
Upfront 2015	9	445
Total	**24**	**1,233.5**

202. Details of the various tariff regimes are given in **Annexure 1E.**

METHODOLOGY FOR DETAILED REVIEW OF WIND POWER PROJECTS

203. A review of NEPRA's tariff shows that the tariff component is based on Energy Based Tariff (**"EBT"**), which includes debt repayment and return on equity (IRR based return).

204. The profitability and dividends of seven IPPs, with operational record of more than three years, was analyzed. As discussed above, the returns of seven IPPs were adjusted to arrive at an Adjusted Profit generated from operations which was then compared with the allowed RoE.

FINDINGS OF THE DETAILED REVIEW OF WIND POWER PROJECTS

205. The finding with respect to the profits and dividends of the Wind IPPs are tabulated below:

Table 30 - Wind IPPs: Profits and Dividends

	Name of Wind Power IPPs	Capacity MW	Years in operation (since CoD)	Share Capital	Profit before tax	Dividend	Average Annual Accounting Return
				Rs. in billion			
1	FFC Energy Limited	49.5	6	2.44	4.21	0.80	29%
2	Sapphire Wind Power Company Ltd.	52.8	4	3.26	3.74	0.73	29%
3	Three Gorges First Wind Farm Ltd.	49.5	4	2.55	3.59	-	28%
4	Hydro China Dawood Power Pvt. Ltd.	49.5	4	3.47	2.80	0.88	27%
5	Foundation Wind Energy-II Pvt. Ltd.	50	5	3.53	4.13	0.35	23%
6	Foundation Wind Energy-I Pvt. Ltd	50	5	3.50	4.05	0.15	23%
7	Zorlu Energy Pakistan Ltd	56.4	6	2.92	3.47	-	20%

206. The Wind IPPs earned an average annual adjusted RoE ranging between 14-21%.

Table 31 - Annual Returns Earned by Wind IPPs

	Project	Years in Operation	Share Capital	Accounting Profit before Tax	Adjusted Profit	Return on Equity Paid	Excess Return	Average Annual RoE Earned	Average Annual RoE Allowed
			Rs. in Billion						
		a	b	c	e	f	g = e - f	h = e/b/a	i = f/b/a
1	Foundation Wind Energy-II Pvt. Ltd.	5	3.53	4.13	3.74	3.60	0.135	21%	20%
2	Sapphire Wind Power Company Ltd.	4	3.26	3.74	2.74	2.68	0.056	21%	21%
3	Zorlu energy Pakistan Ltd.	6	2.92	3.47	3.43	4.62	(1.192)	20%	26%
4	Three Gorges First Wind Farm Ltd.	5	2.55	3.59	2.49	2.48	0.014	20%	19%
5	FFC Energy Ltd.	6	2.44	4.21	2.85	3.42	(0.573)	19%	23%
6	Foundation Wind Energy-I Pvt. Ltd.	5	3.50	4.05	3.07	2.93	0.145	18%	17%
7	Hydro China Dawood Power Pvt. Ltd.	4	3.47	2.80	1.46	1.82	(0.367)	14%	18%
	Total		21.671	25.99	19.78	21.56	(1.782)		

207. As evident there is minimal difference between the annual return earned based on adjusted profit and the RoE allowed as per tariff of these IPPs. However, the following paragraphs detail anomalies identified in the tariff determinations of these IPPs which require immediate rectification.

EXCESS GENERATION

208. Under the Wind Upfront tariffs of 2013 and 2015, the power producer ought to have recovered the entire cost of debt, interest, O&M, insurance and 17% USD IRR, provided they operate the plant at the minimum benchmark (31% under 2013 tariff and 35% under 2015 tariff).

209. Any energy generated in excess of the minimum benchmark leads to additional tariff payments in a pre-determined ratio which includes debt and interest components. Therefore, with respect to production over and above the minimum benchmark, the IPP will be able to recover debt and interest (beside O&M and RoE) over and above the amount that actually has to be paid to the lenders.

210. When, on a sample basis, the annual Net Electrical Output was compared with the benchmark energy based on an annual plant capacity factor, the actual power generation has not meaningfully exceeded the minimum benchmark during the operational period under review.

211. Although this has not resulted in any excess payments so far, this tariff determination methodology could be problematic in the future since any payment above the production benchmark will effectively translate into excess payment because the debt and interest components are already fully recoverable in the fixed costs guaranteed up to the production benchmark.

INTERNAL RATE OF RETURN

212. Due to the mismatch between annual payments envisaged by NEPRA of USD based 17% IRR versus the monthly payments made by CPPA-G, the actual IRR earned by these IPPs works out to be higher than the IRR allowed by NEPRA.

213. The Wind IPPs under review have therefore been incorrectly allowed 18.39% return instead of 17% return. This has led to excess payment of **Rs.1.58 billion** during the

period under review. These seven IPPs will earn additional **Rs.4.75 billion** excess return on equity till the end of their respective contract periods on account of this timing mismatch leading to total excess payment of **Rs.6.32 billion.**

Table 32 - Wind IPPs: Projected Excess Return Over Life of Project

	Project	Years in Operation	Allowed Return on Equity	Return on Equity Paid	IRR Miscalculation from COD till 2018/2019	IRR Miscalculation in rest of Project Life	IRR Miscalculation for the Entire Project Life (20 years)
			Rs. in Billion				
1	Zorlu energy Pakistan Ltd	6	4.27	4.62	0.35	0.82	1.17
2	Foundation Wind Energy-II Pvt. Ltd	5	3.33	3.60	0.27	0.82	1.09
3	Sapphire Wind Power Company Limited	4	2.47	2.68	0.21	0.86	1.07
4	Foundation Wind Energy-I Pvt. Ltd	5	2.71	2.93	0.22	0.66	0.88
5	FFC Energy Limited	6	3.16	3.42	0.26	0.60	0.86
6	Three Gorges First Wind Farm	5	2.29	2.48	0.19	0.56	0.75
7	Hydro China Dawood Power PVT LTD	4	1.75	1.82	0.08	0.43	0.50
	Total		**19.99**	**21.56**	**1.58**	**4.75**	**6.32**

214. This **Rs. 6.32 billion** excess payment on account of miscalculation in IRR over the project life of 20 years to seven IPPs having 357.7 MW means excess earning of **Rs. 17.67 million per MW**. If projected for all operational wind IPPs (1,233.5 MW), this works out to excess RoE of **Rs. 21.8 billon,** excluding the impact of future depreciation of PKR, over the project life of 20 years.

MISMATCH IN DEBT REPAYMENT

215. As discussed in detail under the section on 2002 Policy IPPs, the mismatch between the timing of debt payment envisaged by NEPRA for computation of debt service component (quarterly) versus the actual payments made by CPPA-G (monthly) leads to additional working capital availability for the IPPs which eventually leads to additional profitability.

216. It is not possible to reasonably estimate the impact of this mismatch due to unavailability of various assumptions at this time. However, it needs to be rectified by NEPRA and CPPA-G as it has the potential to have a significant impact on future payments.

MISREPRESENTATION IN SETUP COST

217. While reviewing the tariff determination in the case of Zorlu Enerji Pakistan Limited, misrepresentation in setup cost was observed. Zorlu filed a motion for leave for review, along-with relevant documentary evidence against NEPRA's decision in the matter of its COD tariff adjustment.

218. During this process, NEPRA came across contradictory documentary evidence pertaining to EPC price. Along with the review motion, Zorlu submitted an EPC contract bearing EPC price of € 6.742 million. Earlier, at the time of tariff determination, it had submitted EPC price of € 8.316 million for the same equipment with the same contractor on the same date. NEPRA also noted that the recently submitted EPC contract's page bearing EPC price was not even initialed by both parties to the contract. Upon unsatisfactory explanation by Zorlu, NEPRA awarded tariff on the basis of initialed EPC Contract and no further action was taken against Zorlu.

Solar-based IPPs set-up under 2006 Policy

219. The tariff wise details of Solar IPPs which have achieved CoD under the 2006 RE Policy is as follows:

Table 33 - Solar IPPs under 2006 Policy

Tariff regime	No. of IPPs	Capacity MW
Solar Upfront 2014	-	-
Solar Upfront 2015 - I	4	400
Solar Upfront 2015 – II	3	80
	7	480

220. Details of these tariff regimes is contained at **Annexure 1F.**

METHODOLOGY FOR DETAILED REVIEW OF SOLAR POWER PROJECTS

221. NEPRA's tariff determinations including its internal workings, assumptions and calculation of IRR were reviewed. The tariff is single-part, i.e. EBT which includes debt repayment and RoE (IRR based return) to the sponsors.

222. The profitability and dividend of four IPPs, which have operational record of at least three years were analyzed. As discussed earlier, their returns were adjusted to arrive

at an Adjusted Profit generated from operations in line with the review methodology, which was then compared with the allowed RoE.

FINDINGS OF THE DETAILED REVIEW OF SOLAR PROJECTS

223. The finding with respect to the profits and dividends of the Solar IPPs are tabulated below:

Table 34 – Solar IPPs: Profits and Dividends

	Name of Solar Power IPPs	Capacity	Years in operation since CoD	Share Capital	Profit before tax	Dividend	Average Annual accounting return
			Rs. in billion				
			a	b	c	d	e = c/b/a
1	QA Solar Power Pvt. Ltd.	100	4	3.81	5.39	2.20	35%
2	Apollo Solar Development Pakistan Ltd.	100	3	3.45	2.58	0.66	25%
3	Crest Energy Pakistan Ltd.	100	3	3.83	1.89	0.46	16%
4	Best Green Energy Pakistan Ltd.	100	3	3.23	1.38	0.19	14%

224. The Solar IPPs earned average adjusted annual RoE ranging between 12-16%.

Table 35 - Solar IPPs: Annual Returns Earned

	Project	Years in operation since CoD	Share capital	Accounting Profit before tax	Adjusted Profit	RoE Paid	Excess Return	Average Annual RoE Earned	Average Annual RoE Allowed
			Rs. in Billion						
		a	b	c	d	e	f =d-e	g = d/b/a	h= e/b/a
1	QA Solar Power Pvt. Ltd	4	3.81	5.39	1.86	3.77	(1.906)	12%	25%
2	Apollo Solar Development Pakistan Ltd.	3	3.45	2.58	1.52	1.81	(0.283)	15%	17%
3	Crest Energy Pakistan Ltd	3	3.83	1.89	1.89	1.94	(0.051)	16%	17%
4	Best Green Energy Pakistan Ltd	3	3.23	1.38	1.41	1.56	(0.148)	15%	16%
	Total			**11.24**	**6.69**	**9.07**	**(2.388)**		

225. As evident there is minimal difference between the annual return earned based on adjusted profit and the RoE allowed as per tariff of these IPPs. However, the following paragraphs detail anomalies identified in the tariff determinations of these IPPs which require immediate rectification.

EXCESS GENERATION

226. Under the solar tariff regimes, the power producer ought to have recovered the entire cost of debt, interest, O&M, insurance and RoE provided they operate the plant at the minimum benchmark. Any energy generated in excess of the minimum benchmark leads to additional tariff payments in a pre-determined ratio. Payment of the debt and interest components is already accounted for at the net annual capacity factor. Therefore, if the IPP operates in case of excess generation, it will be able to recover debt and interest over and above the amount that is actually payable to the lenders.

227. When, on a sample basis, the annual Net Electrical Output was compared with the benchmark energy based on an annual plant capacity factor, the actual power generation has not meaningfully exceeded the minimum benchmark during the operational period under review.

228. Although this has not resulted in any excess payments so far, going forward, this tariff determination methodology could be problematic since any payment above the production benchmark will effectively translate into excess payment because the debt and interest components are already fully recoverable in the fixed costs guaranteed up to the production benchmark.

INTERNAL RATE OF RETURN

229. NEPRA has allowed a dollar-based equity IRR of 17% assuming annual payment of return, whereas actual payments of RoE is made to IPPs on a monthly basis by CPPA-G. Consequently, the Solar IPPs earned a higher RoE of 18.39% compared to the allowed return of 17%. In monetary terms, the 4 Solar IPPs have earned an extra return of **Rs.0.69 billion** during the period under review and will earn an additional **Rs.4.48 billion** till the end of their respective contract periods on account of this timing mismatch.

230. In total, **Rs.5.17 billion** will be earned during the entire life of the project due to this error, as detailed in the following table:

Table 36 – Projected Excess Return over Life of Solar IPPs

	Project	Years in operation	Allowed Return on Equity	Return on Equity paid	IRR miscalculation from COD till 2018	IRR miscalculation in rest of project life	IRR miscalculation for the entire project life (25 years)
			Rs. in Billion				
1	QA Solar Power Pvt. Limited	4	3.48	3.76	0.28	1.47	1.75
2	Apollo Solar Development Pakistan Limited	3	1.66	1.80	0.14	1.03	1.17
3	Crest Energy Pakistan Limited	3	1.79	1.94	0.15	1.10	1.25
4	Best Green Energy Pakistan Limited	3	1.43	1.55	0.12	0.88	1.00
	Total		8.36	9.05	0.69	4.68	5.17

MISMATCH IN DEBT REPAYMENT

231. As discussed in detail under the section on 2002 Policy IPPs, the mismatch between the timing of debt payment envisaged by NEPRA for computation of debt service component (quarterly) versus the actual payments made by CPPA-G (monthly) leads to additional working capital availability for the IPPs which eventually leads to additional profitability.

232. Like wind-based IPPs, it is not possible to reasonably estimate the impact of this mismatch due to unavailability of various assumptions. However, it needs to be rectified by NEPRA and CPPA-G as it has the potential to have a significant impact on the future payments.

IPPs set-up under Co-Generation Framework 2013 (Bagasse/Biomass)

233. On March 6, 2013, the ECC expanded the scope of the 2006 Policy to include bagasse, biomass, waste-to-energy and bioenergy technologies and accordingly issued the Framework for Power Co-generation 2013 (**"Framework"**) for power generation facilities commissioned after January 2013 which were utilizing high pressure co-generation based on Bagasse and Biomass.

SALIENT FEATURES OF THE FRAMEWORK

234. The Framework allowed prospective power producers a choice to:

- Develop the power co-generation facility as part of an existing sugar mill; or
- Develop the power co-generation facility as a separate entity.

235. The Power Purchaser was required to mandatorily evacuate all energy offered by the Power Producers, failing which the plants shall be deemed to have been dispatched and energy sold to the Power Purchaser. The entire range of financial and fiscal incentives available to the RE projects under the RE Policy of 2006 were also made applicable to all the projects implemented under the said Framework.

236. NEPRA initiated suo-moto proceedings for the determination of an upfront tariff pursuant to the framework and on May 29, 2013, issued the following Upfront Tariff for New Bagasse based Co-Generation Power Projects 2013 for a 30-year tariff control period:

Table 37 – 2013 Upfront Tariff for New Bagasse Co-Gen

Tariff	Rs. / kWh
1 - 10 years	11.7396
11 - 30 years	7.9147

237. The following 8 projects have achieved CoD under this tariff regime:

Table 38 - 2013 Co-Gen IPPs

Project	Capacity	CoD
JDW-II	26.35	12-Jun-14
JDW-III	26.35	3-Oct-14
RYK Sugar Mills Limited Bagasse Power Plant	30	23-Mar-15
Chiniot Power Limited	57	29-Nov-15
Hamza Sugar Mills	15	10-Mar-17
Layyah Sugar Mills	41	01-Dec-17
Al Moiz Industries Limited	36	04-Jan-19
Chanar Energy Limited	22	15-Feb-19
Total	**253.7**	

238. Salient features of this tariff are as follows:

i. The tariff assumed an Annual Plant Capacity Factor (**"APCF"**) of 45% on the basis of 180 days and plant availability of 92% for Co-generation projects. NEPRA had originally assumed a 50% APCF. However, Pakistan Sugar Mills Association (**"PSMA"**) in its presentation to NEPRA in the hearing objected that 50% APCF as proposed by the Authority was not achievable based on the period of sugar cane crushing season and bagasse availability to the sugar mills during off season for power generation. PSMA submitted that actual crushing season in our country lasts for 100-110 days, therefore, adjusting for shorter crushing season in our country, the realistic APCF for Co-generation projects works out to be around 40% which may be considered by the Authority. Examples of neighboring country was provided where regulator has fixed APCF of 45% based on 180 days (120 days crushing season and 60 days off season). Accordingly, NEPRA granted raise in the base tariff due to change in APCF from 50% to 45%.

ii. Based on the APCF of 45%, annual energy of a capacity of 1 MW (91.5% net capacity after auxiliary load) arrives at 3.607 GWh (1MW x 91.5% x 45% x 365 days x 24 hours), which was used by NEPRA in the calculation of fixed cost components, RoE and debt service cost when determining the tariff.

METHODOLOGY FOR DETAILED REVIEW

239. The operational period for 4 of the 8 Bagasse IPPs was less than three years, and for 2 projects it was less than one year. This was insufficient to review the profitability of these projects holistically. Therefore, the following 4 operational co-generation projects were reviewed which have been operational for more than three years:

Table 39 – Bagasse IPPs under Review

Company	Project	Capacity	CoD
JDW Sugar Mills Limited	JDW-II	26.35	12-Jun-14
	JDW-III	26.35	3-Oct-14
RYK Mills Limited	RYK Sugar Mills Limited Bagasse Power Plant	30	23-Mar-15
Chiniot Power Limited	Chiniot Power Limited	57	29-Nov-15

240. The financial statements of these IPPs were reviewed and, as discussed earlier, their returns were adjusted to arrive at an Adjusted Profit generated from operations in line with the review methodology, which was then compared with the allowed RoE.

241. In the case of JDW Sugar Mills Limited and RYK Mills Limited, the main business of the companies was other than power generation, therefore, all required information pertaining to power generation was not available in their financial statements. Further, in case of Chiniot Power Limited, financial statements for only the first two years were available, consequently it was not possible to analyze the financial statements in detail.

242. However, the collective Adjusted Profit pertaining to projects JDW-II and JDW-III (**"JDW"**) were determined by using information reported in the Group Reportable

Segment under the head "*Co-Generation segment*" in the consolidated financial statements of JDW Sugar Mills Limited.

243. A comparison of the Adjusted Profit with the allowed RoE as per the information provided by CPPA-G showed that there were material excess profits made by JDW. The reasonableness of tariff determination was also reviewed to identify the causes of these excess profits. In this regard, the assumption of plant factor of 45% used in the tariff determination was corroborated with the actual plant utilization (annual Net Electrical Output) as per the information provided by CPPA-G. A similar comparison was also conducted for RYK Sugar Mills Limited Bagasse Power Plant and Chiniot Power Limited.

244. The company wise detailed reports along with respective findings are contained after the implementation plan provided in this report, however, summarized observations are contained in the following paragraphs.

FINDINGS OF DETAILED REVIEW

EXCESS PROFITABILITY: IRR MISCALCULATION

245. NEPRA had allowed a return to the Bagasse IPPs based on 15% USD Equity IRR to be paid annually. In reality, the IPPs are paid their CPP on a monthly basis by CPPA-G, which includes RoE. Because of this mismatch between the timing of payment for computation of IRR, the IRR earned by these IPPs is higher than the IRR allowed by NEPRA, i.e. 18.39% return instead of the allowed 17% return.

246. In monetary terms, this works out to extra earning for the IPPs of **Rs. 0.26 billion** during the last 3-5 years of their operations, i.e. the period under review. It is projected that these four IPPs will earn an additional **Rs.4.62 billion** by the end of their respective contract periods as excess RoE, assuming that USD appreciates against PKR at an average rate of 6% per annum.

247. In total, an excess of **Rs. 4.88 billion** will be earned by these four projects during their project life, details of which are tabulated below:

Table 40 – Excess Profitability: IRR Miscalculation

	Project	Project life	Years in Operation	Return on Equity paid	Return on Equity Allowed	IRR miscalculation from COD	IRR miscalculation in the rest of life	IRR miscalculation for the whole project life
1	Chiniot Power Limited	30	3	1.02	0.95	0.08	2.02	2.10
2	RYK Mills Limited	30	3	0.49	0.46	0.04	1.13	1.17
3	JDW-II	30	5	1.01	0.94	0.08	0.82	0.90
4	JDW-III	30	5	0.96	0.89	0.07	0.64	0.72
						0.26	**4.62**	**4.88**

EXCESS PROFITABILITY: FIXED COSTS AND DEBT SERVICE COSTS

248. The Bagasse power plants under review were producing electricity in excess of the plant factor used by NEPRA for tariff determination. Payment of fixed costs, i.e. fixed O&M – local, working capital, insurance, etc., as well as debt service cost is linked with the plant factor which was determined at 45% in the tariff determination.

249. The electricity generation in excess of 45% plant factor therefore leads to excess payment on account of fixed cost and debt service cost, which is included as a revenue of the IPPs, resulting in excess profits.

250. Since the IPPs under review have produced electricity in excess of 45% plant factor, excess gains were made by the IPPs, details of which are tabulated below:

Table 41 - Excess Profitability: Fixed Costs and Debt Service Costs

Company	Project	Years of operation	Excess gain Rs. in billion
JDW Sugar Mills Limited	JDW-II	5	2.05
	JDW-III	5	1.94
RYK Mills Limited	RYK Sugar Mills Limited Bagasse Power Plant	3	1.0
Chiniot Power Limited	Chiniot Power Limited	3	1.34
	Total		**6.33**

251. It may be noted that the CPPA-G has taken notice of this issue and during 2018, CPPA-G has initiated adjusting/deducting the excess payments made to these four projects. However, the IPPs have challenged the action of CPPA-G in the Islamabad High Court and are claiming that excess gain on account of plant factor is their right. The Honorable Court has referred the case to Secretary, Power Division and a decision in the matter was still pending at the time of submission of this report.

WAY FORWARD – PRIVATE POWER PRODUCERS

252. The exorbitant returns earned by IPPs as detailed in the preceding paragraphs, are generally attributable to:

Misinformation by IPPs

- Information shared by IPPs at the time of tariff determination and CoD adjustment was not commensurate with actual performance

Weaknesses in Governance

- Weak regulatory oversight
- Non-reconsideration of incentives offered by the Federal Government

253. Successive Federal Government policies offered incentives and exorbitant returns leading to significant private investment in the power sector. The fallout of this was:

Excess generation capacity added → Overcapacity coupled with the 'take or pay' provisions → Power tariffs raised → Increased cost of production

254. With the advent of cheap renewables and RLNG spot prices lower than USD 3.00/MMBTU, these industries are finding their own cost-effective solutions and becoming less reliant on the grid to support their power needs. If this trend continues, it will force the most profitable consumers out of the system and increase the power cost to remaining consumers. The power sector in its existing setup is economically unsustainable for Pakistan.

255. The Committee, therefore, suggests four major interventions to address issues pertaining to excess profits and reduce power tariffs for the benefit of the consumers and the economy:

Immediate Interventions Recommended			
Recovery of past excess profits	Claw back mechanism for future excess profit	Switch from USD to PKR based return	Shifting the tariff regime to take and pay structure

Recovery of Past Excess Profits Paid

256. Under the 2002 Policy, projects were to be processed either through:

    a. **International Competitive Bidding ("ICB"):** The project is awarded to the lowest levelized tariff; or

    b. **Negotiation:** NEPRA determines tariff on the basis of information regarding costs and project setup/operations.

257. In the latter case, the tariff was to be awarded under the NEPRA (Tariff Standards and Procedure) Rules, 1998, rule 17(3) of which requires NEPRA to allow "*...licensees the recovery of any and all costs prudently incurred to meet the demonstrated needs of their customers*" and "*...a rate of return on the capital investment of each licensees commensurate to that earned by other investments of comparable risk*". This stipulates a cost-plus regime for grant of power sector tariffs, under which NEPRA is to assess the prudent cost through a process of stakeholder consultation. This prudent cost includes a market-based return on the licensee's investment.

258. Under this tariff structure, the performance of IPPs post-CoD should have been regularly monitored to revisit the basis of tariff and its reasonableness of underlying assumptions. Failing this, excess payments were made in two broad categories:

    a. Misrepresentation by IPPs under different power policies:

        - 2002: Difference between their allowed and actual fuel cost and O&M.
        - 2006: Extra profits because of initial misreporting of annual plant capacity factor of bagasse-based plants and misrepresentation of set-up cost in one wind-based plant.
        - 2015: Difference between set up cost claimed, and actual cost incurred. This has also led to computation of excess profit payment over the project life in one plant.

    b. Systemic errors in tariff determination and tariff component payment frequency, i.e.:

        - Computation of IRR (annual versus monthly);
        - Debt repayment (quarterly/biannual versus monthly) and inventory shortfall; and
        - Duplication of Currency Depreciation in Return.

ADDRESSING MISREPRESENTATION ISSUES

2002 POLICY

259. As stated above, eleven IPPs earned a total of **Rs. 64.22 billion** in excess of regulated profit. Based on historic trends, it is projected that these IPPs will earn an additional Rs.145.23 billion over the remaining years of respective concession periods, aggregating to **Rs. 219.46 billion** over the life of the projects.

260. ***This amount of Rs. 64.22 billion should be recovered from the IPPs since the tariff was awarded under a cost-plus regime where an IPP is only entitled to a regulatory return*** and no justification has been identified in the tariff documentation allowing the IPPs to receive an excess payment on account of fuel, O&M and other factors. ***This should be adjusted against the outstanding dues of each IPP parked in CPPA-G's books.*** The legal perspective will be explained in the later section.

RE POLICY 2006 - WIND & SOLAR PROJECTS

261. Regarding sharing mechanism for energy generation beyond net annual capacity factor whereby an IPP can recover extra fixed costs including debt servicing resulting in profitability beyond what is envisaged under the tariffs, only the RoE component along with key elements of fixed O&M should have been made a part of the tariff. It is therefore recommended that ***the sharing mechanism be reviewed and only the RoE component along with fixed O&M should be allowed on marginal generation beyond allowed net capacity factors in all existing upfront determinations as well as in all future determinations.***

2013 CO-GENERATION FRAMEWORK - BAGASSE AND BIOMASS

262. The excess profits recorded by 4 bagasse based IPPs are on account of misreporting by the Pakistan Sugar Mills Association regarding Annual Plant Capacity Factor. The recovery of fixed cost and debt servicing should have been restricted to the determined plant factor of 45% instead of actual energy generation. ***Fixed cost and debt servicing as a component of payments made for generation above the 45% benchmark are essentially excess gains, which should be recovered, and corrective measures should be taken by NEPRA to address this issue in future.***

2015 POLICY

263. Excess payment to IPPs under the 2015 Policy related to setup cost, totaling **Rs. 32.46 billion:**

   i. Rs. 19.30 billion in relation to PQEPCL; and

   ii. Rs. 13.16 billion in relation to HSR.

264. The difference in setup cost allowed versus reported setup cost is mainly because of:

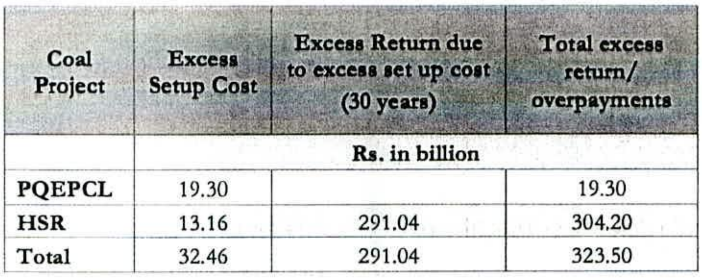
   i. Difference in the construction period assumed versus actual construction period; and

   ii. Incorrect information being submitted to NEPRA on financing cost of these IPPs based on which NEPRA determined its CoD level tariffs.

265. Further, in the case of HSR, NEPRA allowed a return component on 48 months construction period as against the actual construction period of 27 months at the time of HSR's CoD. Combined with extra setup cost, this increased the return payment by about **USD 27.40 million** per year (from USD 70.90 million per year to USD 98.30 million per year).

266. If status quo is maintained, HSR and PQEPCL will collectively earn **Rs. 2,083.82 billion** RoE over their remaining concession periods, out of which at least **Rs. 291.04 billion** is on account of allowance of the excess project cost.

Table 42 - Summary of Excess Profits by 2015 IPPs



Coal Project	Excess Setup Cost	Excess Return due to excess set up cost (30 years)	Total excess return/ overpayments
	Rs. in billion		
PQEPCL	19.30		19.30
HSR	13.16	291.04	304.20
Total	32.46	291.04	323.50

267. The CoD tariff review petitions of these two companies are currently pending before NEPRA and no decision has yet been made by NEPRA till submission of this report.

268. It is therefore recommended that:

a. ***Rs. 32.46 billion be deducted from the project cost of PQEPCL and HSR;***

b. ***The return payment formula be corrected to reflect actual construction time; and***

c. ***Tariff of PQEPCL and HSR be adjusted accordingly.***

269. This will also set a benchmark for CoD adjustments of all coal-based power plants, whether on Thar or imported coal, which are soon to be commissioned, and accordingly going to apply for CoD tariff adjustment before NEPRA.

SYSTEMIC ISSUES

OVERSIGHT IN IRR CALCULATION

270. Certain tariff anomalies were noted in the tariff of all IPPs. One of these related to computation of IRR on an annual basis by NEPRA whereas the payments to IPPs are made on a monthly basis.

271. With respect to the oversight in IRR calculation, a total of **Rs. 11.63 billion** was overpaid, i.e.:

- Rs. 6.46 billion to 13 IPPs under 2002 Policy
- Rs. 1.58 billion to 7 Wind IPPs
- Rs. 0.26 billion to 4 Bagasse IPPs
- Rs. 0.69 billion to 4 solar IPPs under 2006 Policy
- Rs. 2.64 billion to 2 coal based IPPs under 2015 Policy

272. If this error is not rectified, ***assuming an annual rupee depreciation of 6% against USD, these IPPs having 6,471.40 MW capacity will cumulatively earn Rs. 221.40 billion over remaining years of their respective concession periods, totaling Rs. 232.80 billion over the entire concession periods.*** Other than 1994 & 1995 Policies IPPs, for the remaining installed capacity of the 13,156 MW, an amount of **Rs. 565.88 billion** has been estimated as payments on this account. The 2015 projects (coal & RLNG) alone would contribute around Rs. 452.57 billion of this total over payment on account of IRR miscalculation.

273. ***Payment made on this account should be recovered and this error may be rectified in all future tariff determinations/payments.***

274. IPP wise detail of these oversights is attached as **Annexure 1G**.

OVERSIGHT IN DEBT REPAYMENT TERMS AND INVENTORY SHORTFALL

275. With regards to issues pertaining to debt repayment and inventory shortfalls, as discussed earlier in their respective sections, the excess amount on account of profitability worked out to be **Rs. 2.14 billion** and **Rs. 3.63 billion**, respectively under 2002 Policy IPPs. However, for IPPs established under other policies, this exercise was not undertaken because of lack of data.

276. ***Payment made on account of debt repayment and inventory shortfall should be recovered and this error may be rectified in all future tariff determinations/payments.***

277. IPP wise detail of these oversights is attached as **Annexure 1H**.

DUPLICATION OF CURRENCY DEPRECIATION IN ROE

278. As discussed above in detail, the determination of IRR on the basis of PIBs, when indexed to USD/PKR parity vide amendment in 2007, is in fact duplication of premium for depreciation of PKR against USD.

279. The impact of this systemic error has so far contributed to excess payments of Rs. 16.48 billion to 11 IPPs under the aforesaid Policy. The issue of double counting also exists in other IPPs established under various policies, however, the impact has not been calculated due to lack of relevant information. ***The Committee is of the view that the excess amount should be recovered and for future, reference be made to the recommendation given in sub-section "Switch from USD to PKR Based Return" below.***

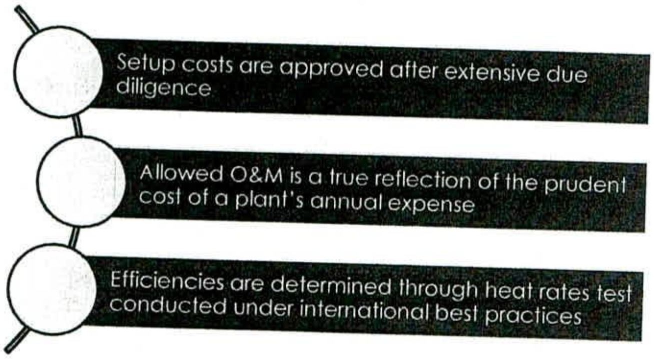
Clawback Mechanism for Potential Excess Profits

280. The claw back mechanism incentivizes an IPP to efficiently manage its operations and share the benefit of efficiency with consumers in a certain pre-defined ratio. This mechanism is also useful when existing knowledge is not at pace with the changing

landscape of technology which may lead to inaccurate forecasting of CAPEX and OPEX assessment by NEPRA.

281. This mechanism is also prescribed in neighboring India, where savings in EPP are shared between the plant owners and end consumers[34]. It protects consumers in case of excess gains obtained through misinformation, deceit or fraud. Unfortunately, no such mechanism was prescribed for any of the IPPs in Pakistan and there is an immediate need to prescribe a sharing mechanism of excess profits for the entire generating sector going forward.

282. For clawback to be introduced, it needs to be ensured that:



- Setup costs are approved after extensive due diligence
- Allowed O&M is a true reflection of the prudent cost of a plant's annual expense
- Efficiencies are determined through heat rates test conducted under international best practices

283. These steps may lead to a tariff truly reflective of cost/expense with a reasonable rate of return being given to compensate the investment. If an IPP lowers expense and improves its performance benchmark, any resulting benefit in profit ought to be shared with consumers. This way an IPP will be encouraged to be more efficient.

284. It is important to note that the question of claw back being applied retrospectively does not arise with respect to the reasons highlighted above. Instead past payments are proposed to be fully recovered in outstanding payments or future payments to IPPs. ***In future, as a matter of policy, claw back mechanisms are recommended to be introduced whereby extra profit made by an IPP for improved efficiency is shared with the consumers in a certain pre-determined ratio.*** Such clawback mechanism will be possible when existing tariffs are reduced to levels reflective of the true and prudent cost of operations of generating companies.

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[34] http://www.cercind.gov.in/2019/regulation/Tariff%20Regulations-2019.pdf

285. Going forward, the minimum level of required disclosures should be demanded by NEPRA. This should include:

c. **Revenue side:** Break up and complete disclosure of the revenue of respective IPPs tariff components such as fuel, variable and fixed O&M - foreign and local components, debt servicing (principle & interest), insurance, working capital, RoE and RoEDC, LPS on account of energy and capacity purchase price, etc.

d. **Expense side:** Breakdown of raw material consumed into fuel and lubricants, variable and fixed O&M – foreign and local components, comprehensive details of fuel inventory such as opening stock, addition, closing stock in quantity and in amount, capital expenditure incurred on major overhauls, capital spares, etc.

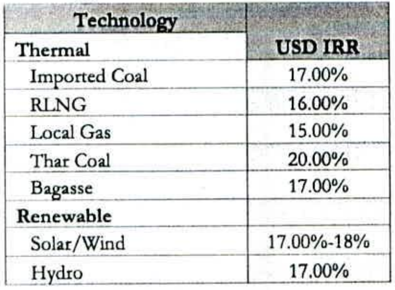
Switch from USD to PKR Based Returns

286. In context of a high installed capacity against low demand, a continuous USD appreciation against the PKR will lead to further increasing consumer tariffs. ***This is an unsustainable situation where we might end up increasing already high tariffs to completely unaffordable levels over the coming years.***

287. It is also worth mentioning that coal-based plants under Power Policy 2015 have been given USD IRR as high as 20%, which translates to a USD RoE of 34.49% . The USD ROE `of 34.49%[35] was given when reference PKR to USD rate was 97.1. If the current rate of 155 is assumed, ***a USD RoE of 34.49% translates to about 55% PKR RoE.***

288. The returns being offered to different technology power plants which are currently operational at national grid are tabulated as follows[36]:

Table 43 - Returns being offered to different technology power plants



Technology	USD IRR
Thermal	
Imported Coal	17.00%
RLNG	16.00%
Local Gas	15.00%
Thar Coal	20.00%
Bagasse	17.00%
Renewable	
Solar/Wind	17.00%-18%
Hydro	17.00%

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[35] Upfront Thar Coal Tariff 2014

[36] https://nepra.org.pk/tariff/Tariff/Consultative%20Session%2022%2011%2018%20Public.pdf

289. To understand the benefit of switching to guaranteed returns in local currency, the following comparison was developed for 11 IPPs under the 2002 Policy and 2 IPPs under the 2015 Policy:

A. Business as usual: Returns continue to be indexed with USD assuming conservatively annual average PKR depreciation of 6% against USD (actual depreciation has been around 6.87% during the last 9 years[37]);

B. Return fixed at USD/PKR exchange rate level of June 30, 2019: No further indexation allowed beyond this date till the expiry of concession agreement; and

C. Return fixed at USD/PKR exchange rate at the level of the first complete year after COD: No indexation allowed beyond this date till the expiry of concession period.

Since coal plants are recently commissioned, options B & C for coal plants will remain the same.

Table 44 – Comparison of Return with and without USD Indexation

					A			B			C		
	Project	**Project Life**	**Remaining Life**	**Equity Injected**	**Return Already Allowed**	**RoE to be paid during Remaning Life**	**Total Return**	**Return Already Allowed**	**Remaining Return at 06/19 USD/PKR Parity**	**Total Return**	**Return First year after CoD USD/PKR parity**	**Return for Remaining Life**	**Total Return**
Power Policy 2002									**Rs. in Billion**				
1	UCH-II	25	20	11.20	9.79	107.25	117.04	9.79	49.75	59.53	2.06	41.11	51.38
2	Saif Power Limited	30	21	3.86	9.22	54.22	63.43	9.22	22.77	31.98	0.87	18.25	26.07
3	Engro PowerGen QadirPur Limited	25	16	3.24	8.95	33.91	42.86	8.95	19.23	28.18	0.91	14.64	22.87
4	Atlas Power Limited	25	17	4.74	8.12	35.72	43.84	8.12	19.74	27.87	0.89	15.06	22.14
5	Nishat Power Limited	25	17	3.54	6.17	29.64	35.81	6.17	14.89	21.06	0.63	10.69	15.72
6	Saphire Electric Power Limited	30	22	4.24	8.08	70.11	78.18	8.08	26.91	34.98	0.79	17.43	23.77
7	Orient Power Company Limited	30	21	4.45	7.87	59.23	67.09	7.87	24.49	32.35	0.61	12.83	18.32
8	Liberty Power tech Limited	25	17	5.05	7.52	35.34	42.85	7.52	19.49	27.01	0.90	15.29	22.49
9	Nishat Chunian Limited	25	17	3.67	6.52	27.81	34.33	6.52	15.81	22.33	0.70	11.83	17.40
10	Foundation Power Company (Daharki) Limited	25	17	3.80	6.40	35.39	41.79	6.40	17.11	23.52	0.70	11.82	17.39
11	Attock Gen Limited	25	16	3.00	5.78	22.43	28.20	5.78	11.83	17.61	0.59	9.37	14.64
	Total			**50.79**	**84.41**	**511.03**	**595.43**	**84.41**	**242.02**	**326.42**	**9.63**	**178.31**	**252.19**
Power Policy 2015													
1	Port Qasim Electric Power Company Pvt. Ltd.	30	29	45.19	14.67	1,144.73	1,159.40	14.67	425.29	439.95	14.67	425.29	439.95
2	Huaneng Shandong Ruyi (Pak) Energy Pvt. Ltd.*	30	28	37.82	26.92	939.09	966.01	12.93	361.99	374.91	12.93	361.99	374.91
	Total			**83.01**	**41.58**	**2,083.82**	**2,125.40**	**27.59**	**787.27**	**814.87**	**27.59**	**787.27**	**814.87**

**from COD till Nov 2019*

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[37] It may be argued that 6% annual depreciation of PKR is high for the estimate, however, at the time of the 1994 Policy, USD 1 was equivalent to PKR 30.03, which, with current rate of PKR 155/USD 1 translates to a Compound Annual Growth Rate of 6.5% during the last 26 years.

290. In scenario A, which assumes continuation of returns being indexed to USD, the 2002 Policy IPPs will profit of **Rs. 511.03 billion** for the remaining terms of the contract for a combined invested equity of Rs. 50.79 billion, whereas the two plants under 2015 Policy will receive a whopping **Rs. 2,083.82 billion** profit payment during the remaining 28/29 years of operation against their combined equity of Rs. 83.01 billion. We have seen similar profitability numbers in 1994 and 2002 Policies.

291. In scenario B, where returns are fixed at the level of June 30, 2019 USD/PKR exchange rate, IPPs under the 2002 Policy will get a return payment for the remaining term of the contracts of ***Rs. 326.42 billion instead of Rs. 511.03 billion***. In scenario C, if the 2002 IPPs return was fixed in PKR based on USD/PKR exchange rate of first year after COD without any USD indexation, the future payment of return will be ***Rs. 178.31 billion***.

292. For the two coal projects, against their total investment of Rs. 83.01 billion, ***the payment of return can be reduced to Rs. 787.27 billion instead of Rs. 2,083.82 billion if the USD/PKR exchange rate is fixed at June 30, 2019 parity***. Even after this, the two coal projects will still receive, on average, RoE of 33.24% per annum.

293. under the current formula, in two years of operation, HSR has already recovered 71.18% of its original equity invested whereas PQEPCL has recovered 32.46% of its original equity in the first year of operation. These are just two plants under the 2015 policy and more than 6000 MW will join the system at a higher percentage of return.

294. The Committee estimated the impact of switch from USD to PKR based return for the whole sector excluding 1994 plants (13,154 MW). The Government would have to pay Rs. 7,992 billion over the remaining lives of these plants in case USD indexation is continued compared to Rs. 3,266 billion if it switches to PKR based return fixing the PKR/USD parity to first year after CoD, leading to saving of more than Rs. 4,700 billion. This amount will increase substantially due to capacity additions in the future.

Table 45 – Savings: Switching from USD to PKR based Returns

Policy	Total Return on Equity expected under Existing arrangement	Total Return on Equity expected under first year USD/PKR at COD
	Rs. in billion	
2002 (2,934 MW)	595.43	252.19
2015 (8,253 MW)	**6,514.31**	**2,547.39**
2 coal (2,640 MW)	2,083.82	814.87
Hub + Engro thar (1,980 MW)	1,562.87	611.15
RLNG (3,633 MW)	2,867.62	1,121.37
RE 2006		
Wind (1,233 MW)	619.26	336.69
Solar (480 MW)	190.86	86.97
Bagasse (254 MW)	73.08	43.14
	7,992.94	3,266.38

295. ***It is therefore abundantly clear that the existing system of offering returns indexed with USD is not sustainable***. It is important to highlight that in neighboring India, return offered is 16% in Indian Rupees.

296. A separate component of RoEDC is also offered in Pakistan which the Committee could not find being offered in any other international jurisdiction. An examination of the breakup of return allowed to the IPPs showed that 11 IPPs under the 2002 Policy received **Rs. 17.25 billion** on account of RoEDC during the first 9 years of operation. In just 26 months ending November 2019, HSR received Rs. 10.08 billion under RoEDC which is 27% of the approved invested equity. This practice should therefore be discontinued in the interest of the consumers and a simple RoE should be allowed without incorporating RoEDC.

Shift from Take or Pay Contract Provisions

297. Beside USD indexation of returns, ToP provisions in the PPAs between the Federal Government and IPPs is another major factor contributing to the unsustainably high cost of electricity. With 30% excess capacity in the system and Rs. 900 billion expected capacity payments next year, a switch to TaP provisions can create substantial savings for the country. **Annexure 11** illustrates the capacity payments that the Federal Government made during 2018-19 to eleven plants of 2002 and one plant of 2015, and annual savings which can be made only from these plants by switching to TaP.

298. In Pakistan, successive power generation policies have reinforced the requirement of a ToP based arrangement wherein capacity payments were to be made to the IPPs, provided they were available for dispatch, regardless of the actual power purchased by the Federal Government. Such contracts are designed to suit project lenders who have committed to majority of the project cost with limited recourse.

299. Further, ToP provisions extend over the life of the project, i.e. 25-30 years, which is much longer than the debt repayment period, being around 10 years in Pakistan. Therefore, despite full repayment of their debt, investors continue to get the guaranteed return based on ToP contracts for years 11-25 or 11-30 depending on the terms of the contract. Since these projects are set on BOO basis instead of BOOT basis, payment of guaranteed returns under the ToP arrangement for 25-30 years, instead of only the first few years which may be sufficient to compensate the investors, is completely unjustified and contrary to consumer interest.

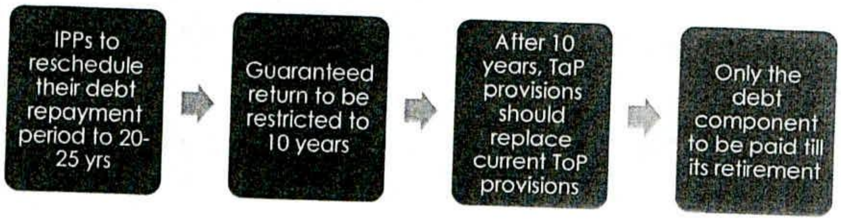
300. Shifting to TaP based contracts will address the accumulation of capacity payments as well as enable the move to a competitive power market structure, as explained in Section 3 of this Report.

301. Since long-term debts have not been fully paid for every IPP, the following strategy is recommended to shift all IPPs to TaP contracts.

2015 POLICY

302. The majority of projects implemented under the 2015 Policy have recently commenced operations, therefore, their long-term debts are still outstanding. In fact, the repayment of debt has been allowed in a relatively short period of 10-12 years. These front-loaded tariffs are going to increase the capacity payment obligation of the Federal Government, therefore, as a matter of policy, ***negotiation should be started with these IPPs for debt rescheduling to 20-25 years instead of the current 10 to 12-year arrangement***.

303. This would flatten the prevailing front-loaded tariff structure, thereby reducing the immediate financial burden of end-consumers. In order to move these plants towards a TaP structure, the following steps are recommended:


IPPs to reschedule their debt repayment period to 20-25 yrs
Guaranteed return to be restricted to 10 years
After 10 years, TaP provisions should replace current ToP provisions
Only the debt component to be paid till its retirement

2006 RE POLICY AND THE 2013 FRAMEWORK FOR BAGASSE

304. Other than the 7 cost-plus based wind IPPs, all power generation facilities in this category assume the variability of wind risk. This means that the Federal Government is not obliged to make any capacity payments to these IPPs regardless of their utilization.

305. Even in the case of the 7 cost-plus wind IPPs, where the Federal Government has tied itself with mandatory capacity payments based on determined benchmark levels, the quantum of capacity payments is not significant enough to affect the overall annual capacity payment of the sector. The projects in this category are therefore largely aligned to the proposed TaP contractual arrangement.

IPPS ESTABLISHED UNDER THE PREVIOUS 1994 AND 2002 POLICIES

306. Except for Davis Energen, all IPPs under the 1994 Policy have paid back their debts. In the case of IPPs with 8 to 9 years of operation under the 2002 Policy, debt is expected to be retired soon, with the exception of Star Hydro and UCH-II which were commissioned in 2017 and 2014 respectively. The years of operations for each of these IPPs is provided in **Annexure 1J** for reference.

307. Therefore, the Federal Government should shift their contracts from ToP to TaP immediately after the payment of their respective long-term debts.

308. If negotiations with the relevant IPPs are unsuccessful, some of the power plants are recommended to be retired. For this purpose, a study of the Tentative Dispatch Plan 2020 (prepared with help of SDDP Software) was undertaken, which has also analyzed the past six-months and expected future utilizations of the plants established under the said power policies. Plants with less than 3% future expected utilization (as per NTDC's estimate) have thereby been identified for the purpose of shut down. Details are contained in **Annexure 1K**.

309. Based on this methodology, a total of 9 power plants under the 1994 Policy and 5 power plants under the 2002 Policy have been shortlisted. However, before arriving at a final informed decision regarding retirement, a technical feasibility in this regard may be carried out to address constraints which may arise due to closure of these plants such as overloading of the system, low voltage issues, stability issues, etc.

310. A review of the standardized PPAs and IAs for the 1994 and 2002 power policies signed with IPPs was also undertaken and an overview of compensation clauses as well as legal clauses covering termination is given at **Annexure 1L**, while the policy-wise outcome is given below.

RETIREMENT COMPENSATION UNDER POWER POLICY 1994

311. The compensation amount required to be paid for retiring the plants under the 1994 Policy could not be worked out as component (c) of the compensation amount listed in the Implementation Agreement (**"IA"**) is based on Net Cash Flows of the project which were presented to the lenders at the time of Financial Closing in the 90s which was not available with the Committee. If the Federal Government decides to go ahead with the closure of these plants, this information will have to be obtained from the lenders or the IPPs.

RETIREMENT COMPENSATION UNDER POWER POLICY 2002

312. In order to determine the compensation amount required to be paid in line with the IA for retiring the plants under the 2002 Policy (**"Termination Cost"**), the relevant information for IA's compensation components (a), (b), (c) and (d) was obtained from NEPRA's tariff determinations and audited financial statements of the respective IPPs.

313. Capacity payments which will be required to be paid to these IPPs for the remaining lives of the projects, regardless of their utilization in case these are not retired, was also calculated assuming the same growth in tariff components as observed in the past. These excess capacity payments will be more than what the potential termination cost would be and therefore, the difference between the two would actually be savings for the Federal Government of **Rs. 188.74 billion** for four plants under the 2002 Policy:

Table 46 – Difference between Termination Cost and Excess Capacity Payments

IPP	Remaining project life	Future Capacity Payments	Termination Cost	Saving by Government
	Years	Rs. in Billion		
Attock Gen Ltd.	15	35.96	0.55	35.4
Atlas Power Ltd.	15	54.54	2.25	52.29
Liberty Power Tech Ltd.	16	55.92	7.46	48.46
Nishat Chunian Ltd.	16	47.97	-4.62	52.58
Total		**194.38**	**5.64**	**188.74**

314. It is pertinent to note that these workings and future projections have been prepared as per the latest reported financial statements/financial data i.e. June 30, 2019 which are applicable if these projects are retired before June 30, 2020. If retired after June 30, 2020, the calculations will change. This working will also require further verification by an independent auditor before a final decision is taken. An IPP-wise detailed analysis for retirement of these 4 IPPs is provided in **Annexure 1M**.

315. If the plants set up under the 1994 and 2002 Policies agree to shift to TaP, then it is irrelevant whether these plants remain in operation or retire because the Federal Government will not be liable to pay them any capacity payments and will only pay them in accordance with actual power generation.

316. In case an agreement cannot be reached on shifting to TaP mode, retirement of plants other than the ones mentioned earlier (9 plants under 1994 Policy and 5 plants under 2002 Policy) can also be considered subject to technical feasibilities. The financial impact of retiring eleven IPPs established under the 2002 power policy, though not recommended due to technical reasons, is tabulated below to highlight potential savings if such a need arises in the future:

Table 47 – 2002 Policy: Financial Impact of Termination

	IPP	Remaining Project Life	Expected Capacity Payments - Future	Termination Cost	Saving by Government
		Years	Rs. in Billion		
1	Attock Gen Ltd.	15	35.96	0.55	35.40
2	Atlas Power Ltd.	15	54.54	2.25	52.29
3	Liberty Power Tech Ltd.	16	55.92	7.46	48.46
4	Nishat Chunian Ltd.	16	47.97	-4.62	52.58
5	Nishat Power Limited	16	51.85	-1.41	53.26
6	UCH-II	19	198.49	54.95	143.53
7	Engro Power Gen Qadir Pur Limited	16	48.88	2.46	46.42
8	Foundation Power Company (Daharki) Ltd.	16	53.67	4.25	49.42
9	Sapphire Electric Power Limited	21	98.13	3.49	94.63
10	Saif Power Limited	21	79.54	3.56	75.98
11	Orient Power Company Limited	21	91.59	4.37	87.21
Totals			**816.52**	**77.32**	**739.21**

Strategy for Way Forward

317. The Federal Government has two options for addressing the problems identified in tariff and operations of IPPs:

OPTION 1

318. A negotiated settlement is the preferred option which will require engagement of all stakeholders with a view to arrive at an agreement which ensures that Pakistan's power sector is financially and operationally sustainable in future. This will also be in the interest of the IPPs since they will be able to receive timely payments.

OPTION 2

319. The Federal Government can undertake a forensic audit of all companies with a view to establishing further wrongdoings which were not identifiable under the scope of this Report. This will require a 2-pronged approach discussed below.

FORENSIC AUDIT BY THE FEDERAL GOVERNMENT

320. Various risks were discussed during the review of IPPs which could not be addressed on account of limitations pertaining to budget and the need for a detailed forensic audit. Suspicion was raised about the authenticity of the projects' set-up cost figures submitted by IPPs which may have allowed some investors to recover their equity at the start of the projects, and therefore, any return being paid to them by the Federal Government is unjustified. Similar observations were made about quantity and quality of fuel/coal used by certain IPPs while submitting inflated invoices to CPPA-G.

321. A forensic investigation is therefore recommended, covering:

    a. Misreporting in the financial statements;

    b. Over invoicing in acquisition of plant;

    c. Over invoicing in fuel usage and misreporting in its quality;

    d. Heat rate and annual plant capacity factor; and

    e. Kickback and unlawful commissions in purchase of fuel and other matters.

322. Accordingly, the companies which are found to have misrepresented or misreported may be proceeded against as per applicable law, including potentially in

accordance with Section 16.1(f) of the standard PPA which identifies "*any statement, representation or warranty by the Company in this Agreement (or in a certificate delivered pursuant to Section 2.8) proving to have been incorrect, in any material respect, when made or when reaffirmed and such incorrect statement, representation or warranty having a material adverse effect on the Company's ability to perform its obligations under this Agreement or having a material adverse effect on the rights or obligations of the Power Purchaser under this Agreement;*" as an event of default by the company.

323. The setup cost of two coal-based plants, HSR and PQEPCL, reported in the financial statements seems to be considerably high. A preliminary analysis revealed that a power plant with similar technology is planned by the Jamshoro Power Company Limited (a Federal Government owned company) for which International Competitive Bidding was carried out for EPC contract as required under PPRA rules. As a result, the EPC price of around USD 875 million was established for the two units of 660 MW, which works out to USD 0.66 million/MW.

324. However, the actual capital cost without jetty allowed to HSR under the Upfront Coal Tariff 2014 at the CoD stage was 1.00 million/MW (USD 1,321.75 million). Although the capital cost of HSR cannot be directly compared with the EPC cost of Jamshoro since capital cost includes EPC as well as non-EPC components, the difference of around USD 450 million between the capital cost and the EPC cost cannot justify the capital cost approved for HSR. This establishes the possibility that various power sector investors are taking out their equity upfront by over-invoicing the cost of EPC or plant and machinery.

325. During the review of the tariff documentation, it was noted that the revision in of the 1st Upfront Coal Tariff in 2013 was made because of a reconsideration request filed by the Federal Government through the then Ministry of Water and Power (**"MoWP"**) wherein it was stated that "*the investors based on their market due diligence gave feedback to the MoWP/Federal Government that IPP projects opting for the above determined Upfront Tariffs would not be commercially viable. Interactions with different investors have shown that following items need to be rationalized for viable investment in coal-based Power Generation Projects.*

a. Reconsideration of Per Megawatt Capital Cost of the Project

b. Realistic Readjustment of Net Thermal Efficiency

c. Reconsideration of Fixed & Variable Operation and Maintenance (O&M) Cost

d. Change in the Plant Factor of coal-based power generation projects

The outcome of the feedback given by private sector investors suggests that capital costs as assumed by NEPRA for 660MW unit are on the lower side. While comparable gross capital cost for plants manufactured in Europe and America would range between US$ 2-3 million per megawatt, even that based on the Chinese manufactured power plants would not cost lower than USD 1.45-1.70 million per megawatt."

326. With this background, where the information originated from the investors for revision in tariff and other benchmarks, and not based on proper due diligence by NEPRA, the possibility of overpricing in the setup cost is further substantiated.

ACTIONS BY NEPRA

327. NEPRA, in its statutory mandate under the NEPRA Act has the power to address issues in tariff determinations including systemic issues[38] by reviewing its earlier determinations in terms of section 7(1)(g). Further, section 7(6) of the NEPRA Act binds NEPRA to protect the interests of consumers and companies providing electric power services **in accordance with the principles of transparency and impartiality**.

328. In addition to determining rates, charges and other terms and conditions of the supply of electricity services, NEPRA can also review its orders, decisions, or determinations[39]. Proceedings in this regard can be initiated by NEPRA either on its own motion or on an application of an interested party.

329. NEPRA may initiate proceedings for recovery and rectification in respect of following matters:

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[38] Like oversight in IRR calculation, debt repayment mismatch and duplication of currency depreciation in return.

[39] Section 31(2) and (3) of the Act.

a. Excess profits made by IPPs on account of fuel and O&M costs, etc. under the 2002 Policy;

b. Past payment made on account of oversight in IRR calculation, debt repayment mismatch, inventory shortfall, duplication of currency depreciation in return, etc.

c. Excess recovery of fixed costs from IPPs set up under the 2006 Policy including the bagasse Framework 2013.

330. Excess set-up cost allowed to the 2015 Policy IPPs may be addressed by NEPRA in the pending CoD tariff review petitions of coal based IPPs or through a re-determination of tariff.

331. In order to avoid any uncertainty with regard to the payment of excess profits in future, NEPRA may also add a provision in its tariff determination for claw back or sharing of such excess profits on a reasonable predetermined basis as discussed above.

332. Further, CPPA-G, under the supervision of NEPRA, needs to ensure compliance of PPA provisions including the requirement of minimum fuel inventory for which cost of working capital has been allowed to the IPPs and any non-compliance should be adjusted against the tariffs.

333. NEPRA can also undertake various enforcement actions against the generation companies in accordance with Chapter 111A of the NEPRA Act. Under section 27B of this Act, a penalty can be imposed on a company of a minimum of ten million rupees which may extend to two hundred million rupees and, in the case of a continuing default, with an additional fine which may extend to one hundred thousand rupees for every day during which the contravention continues. Further, under section 27C, NEPRA can:

i. Prohibit a generation company, a licensee or a registered person, from providing electric power services; or

ii. In the case of a generation company, prohibit any or all persons from purchasing electricity from such generation facility; or

iii. Require a generation company, a licensee or a registered person, to improve the provision of electric power services so as to ensure compliance with this Act and the rules and regulations made thereunder.

334. NEPRA may also suspend or revoke the generation license under section 28 of the NEPRA Act, in case the concerned company fails to comply with an instruction issued by NEPRA.

335. Since tariffs are determined on the basis of information provided by IPPs, there are many instances where the systemic tariff issues are caused by factually incorrect information provided to NEPRA at the time of seeking the tariff. For example, heat rate curve and O&M estimates in case of 2002 Policy as well as detail of financing costs in case of the 2015 Policy were provided by IPPs whereas annual plant capacity factor data in case of the 2013 Framework was provided by PSMA.

336. Under Pakistani law misrepresentation of material existing facts made by one person to another with knowledge of its falsity and for the purpose of inducing the other person to act, and upon which the other person relies with resulting injury or damage is defined as fraud. It may also be noted that tariff determination is deemed to be a decree of a civil court under Section 40 of the NEPRA Act, which provides that:

> *"The Authority's determinations or decisions by tribunals set up under section 11 of this Act shall be deemed to be decrees of a civil court under the Code of Civil Procedure, 1908 (Act V of 1908)".*

337. Therefore, the principles governing a decree procured through fraud would potentially be applicable in the case of tariff determination which can be proved to have been procured through fraud or misrepresentation. Such an order/decree may also be held voidable at the option of the party adversely affected by it, after it has been established by the relevant authority to be fraudulent. This entails both civil and criminal implications for the party which has acted fraudulently and may also lead to termination of project agreements.

338. It is worth mentioning that the Federal Government has from time to time made amendments in the policies post its approvals. For instance, in the Power Policy 2002, sixteen amendments on different subjects were approved as reported on the PPIB's

website. The majority were incorporated to cover the risk of investors and the most important ones related to USD indexation of returns and allowance of return during construction. These were made with retrospective effect.

339. There is therefore precedent supporting such a move by the Federal Government, and this time, it will be in the interest of consumers and overall economic health of the country which will be protected.

SECTION 2 - CIRCULAR DEBT & DISTRIBUTION INEFFICIENCIES

CIRCULAR DEBT DEFINITION AND BACKGROUND

340. The official definition of circular debt was approved by the ECC in 2014 as: "*the amount of cash shortfall within the Central Power Purchasing Agency (CPPA-G) which it cannot pay to power supply companies. The overdue amount is the result of: (a) the difference between the actual cost and the tariff determined by the NEPRA which is the distribution company's losses above and collections under those allowed by NEPRA; (b) the delayed or non-payment of subsidies by government; and (c) delayed determination and notification of tariffs.*"

341. For the purposes of this report, the **circular debt stock** includes:

    i. The amount of aggregate overdue payables to power suppliers on CPPA-G's balance sheet; and

    ii. The amount picked up from CPPA-G by the PHPL by funding it through Federal Government guaranteed borrowing.

342. Additionally, the **circular debt flow** is the marginal change in outstanding stock of circular debt.

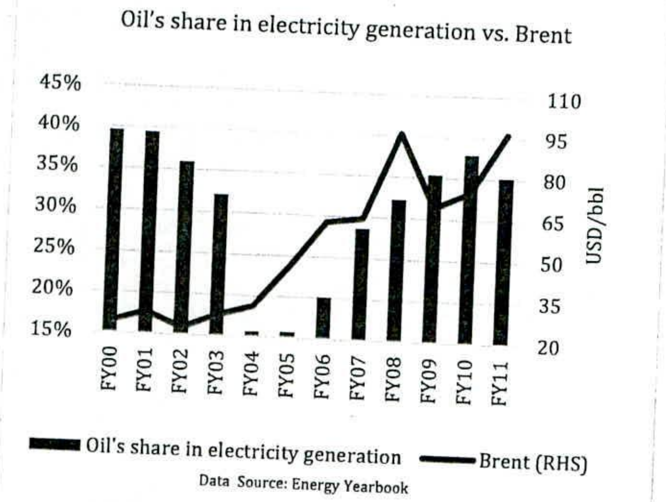
343. In FY2007, overdue trade debts (receivables) started to emerge on the balance sheets of IPPs. Although T&D inefficiencies had previously existed in the system, it had not translated into circular debt because of sufficient difference between cost of generation and end consumer tariff.

344. The problem was triggered by a sharp rise in the cost of generation fuelled by:

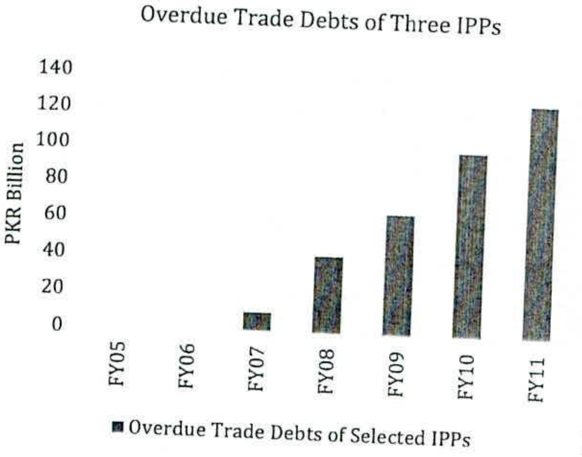
    i. A surge in international oil price;

    ii. An increased share of furnace oil in electricity generation; and

    iii. PKR depreciation.


Oil's share in electricity generation vs. Brent

Data Source: Energy Yearbook


Overdue Trade Debts of Three IPPs

Data Source: Company Financials (HUBCO, KAPCO, Kohinoor Energy)

345. Pakistan's reliance on oil for electricity generation rose sharply in the 1990s when RFO-based power plants were setup by IPPs. However, the early 2000s witnessed a surge in Pakistan's natural gas production and the share of oil in electricity generation fell to less than 16% by FY2005 from almost 40% in FY2000.

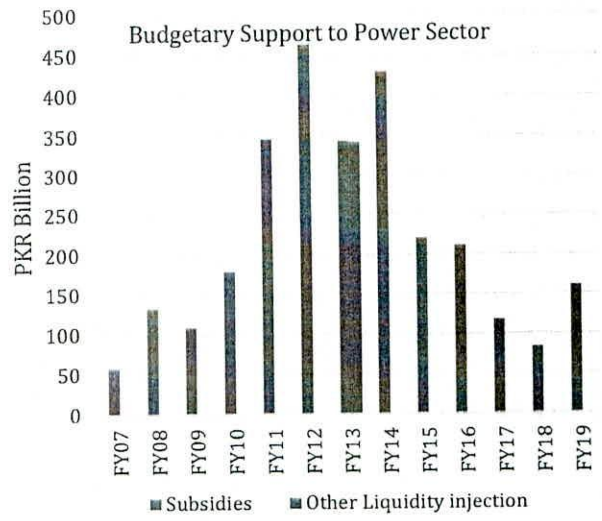
346. By mid 2000s, oil prices surged globally, causing a dramatic shift in domestic gas consumption pattern, which was priced very low relative to oil, therefore its demand from other sectors including transport (CNG) and industry (captive power) increased substantially. Concurrently, the domestic production of natural gas levelled off and subsequently started to decline.

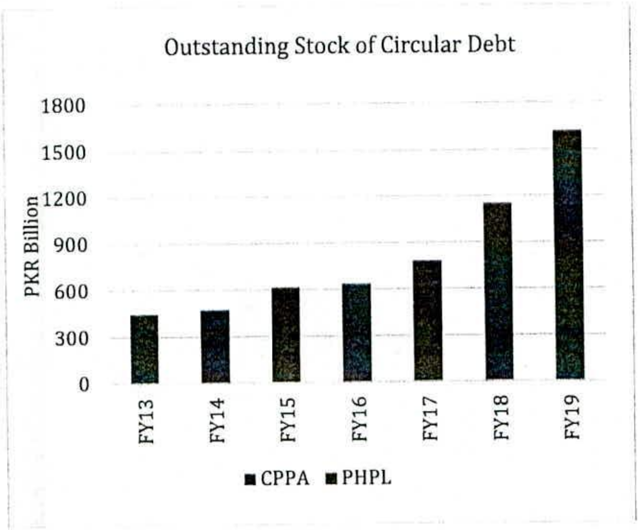
347. This caused a curtailment of natural gas supplies for grid electricity generation thereby increasing the reliance on RFO again. The share of oil in electricity generation jumped to 35% in FY2009 from 16% in FY2005 as illustrated in the chart above. Moreover, hefty PKR depreciation following the 2008 crisis magnified the impact of increasing share of oil in electricity generation pushing the cost of power generation higher. Between FY2005 and FY2010, the cost of generation increased by 148% while average consumer tariff went up by only 33% during this period as tabulated below:

Table 48 - NTDC System – Cost of Generation vs. Average Selling Price (PKR/KWh)

	FY2005	FY2006	FY2007	FY2008	FY2009	FY2010
Cost of generation	2.7	3.0	3.3	4.4	5.4	6.6
Average selling price	3.9	4.0	4.1	4.7	5.2	5.2

348. Successive governments have relied on heavy budgetary support and quasi-fiscal financing to eliminate the circular debt, but these measures addressed the symptoms and not the root cause, therefore the problem has only deepened.





349. The cumulative budgetary support to the power sector amounted to PKR 3,202 billion from FY2007 to FY2019 comprising:

i. PKR 2860 billion as budgetary subsidies; and

ii. PKR 342 billion as other liquidity injection.[40]

Details of this breakdown are contained at **Annexure 2A.**

350. Yet, the circular debt stock has continued to grow and increased by PKR 465 billion in FY2019 to a total of **PKR 1.6 trillion**. With public indebtedness (public debt/GDP) having increased to 85% in FY2019 from 52% in FY2007, the Federal Government's ability to provide fiscal support to the sector is severely constrained.

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[40] This was a part of PKR 480 billion circular debt settlement made in Jun-2013. PKR 342 billion injection was shown as net lending (Others) in the fiscal accounts.

CIRCULAR DEBT FLOW

351. At the micro level, the flow of circular debt is attributable to:

i. A high cost of generation;

ii. Transmission and distribution Inefficiencies; and

iii. Regulatory and fiscal inefficiencies.

High Cost of Generation

352. The high cost of electricity generation remains a major problem, however, its compositional mix has been changing with a shrinking EPP (variable cost) and growing CPP (fixed cost).

Table 49 - NTDC System - Cost of Electricity Generation

		FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019
Units	**KWh Billion**	**88.3**	**95.1**	**97.0**	**101.1**	**107.1**	**120.7**	**122.8**
CPP	PKR Billion	185.0	211.6	246.4	275.0	358.2	470.8	639.6
EPP	PKR Billion	663.0	753.7	629.4	449.3	521.3	661.2	704.8
PPP	**PKR Billion**	**848.0**	**965.2**	**875.8**	**724.4**	**879.5**	**1,132.0**	**1,344.4**
CPP	PKR/KWh	2.1	2.2	2.5	2.7	3.3	3.9	5.2
EPP	PKR/KWh	7.5	7.9	6.5	4.4	4.9	5.5	5.7
PPP	**PKR/KWh**	**9.6**	**10.1**	**9.0**	**7.2**	**8.2**	**9.4**	**10.9**
PKR/USD (Avg.)		96.8	103.0	101.4	104.3	104.8	110.0	136.4
CPP	US¢/KWh	2.2	2.2	2.5	2.6	3.2	3.5	3.8
EPP	US¢/KWh	7.8	7.7	6.4	4.3	4.6	5.0	4.2
PPP	**US¢/KWh**	**9.9**	**9.9**	**8.9**	**6.9**	**7.8**	**8.5**	**8.0**

353. As evident from this table, between FY2014[41] and FY2019:

a. **The total CPP increased** from PKR 212 billion (PKR2.2/KWh) to PKR 640 billion (PKR 5.2/KWh);

b. **The total EPP decreased** from PKR 754 billion (PKR 7.9/KWh) to PKR 705 billion (PKR 5.7/KWh); and

c. **The total PPP (CPP + EPP) increased** from PKR 965 billion (PKR 10.1/KWh) to PKR 1,344 billion (PKR 10.9 /KWh).

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[41] The comparison with FY2014 is illustrative as it was the year of high oil prices with Brent averaging ~USD 110.

354. A host of factors have contributing to this high cost of electricity generation:

- i. Snowballing capacity payments;
- ii. Net Hydel Profit;
- iii. Transmission constraints:
- iv. Minimum plant factor provision for RLNG based plants;
- v. Gas price anomalies; and
- vi. Financing cost of circular debt.

CAPACITY PAYMENTS

355. Although high fuel cost has been the prime reason behind expensive electricity in Pakistan, now snowballing capacity payments are becoming a bigger problem. Majority of the new capacity additions taking place in Pakistan are on conventional fuels with long-term (25-30 year) ToP contracts backed by sovereign guarantees.

356. Since FY2015, about 12,100 MW of net power generation capacities have been added to the power system while another 12,400 MW would be added by FY2025.[42]

357. The new power generation capacities have indeed helped lower the overall fuel cost per unit as they are based on cheaper fuels than furnace oil. However, comparing FY2016 with FY2019, the increase in CPP outweighs this reduction in EPP on per unit basis in both PKR and USD terms. The total CPP amount increased from PKR 275 billion (PKR 2.7/KWh) in FY2016 to PKR 640 billion (PKR5.2/KWh) in FY2019.

NOTE: The Power Purchase Price (PPP) projections by CPPA-G forecasts a progressive increase in CPP to PKR 1.7 trillion by FY2025 from PKR 640 billion in FY2019. This will result in PPP of PKR 14.86 per kWh (EPP PKR 3.45 per kWh and CPP PKR 11.41 per kWh[43]). However, this does not include the possibility of shift to captive power by bulk power customers which will further decrease the actual demand from the grid, hence increasing CPP on per kWh basis which will in turn increase the overall tariff for the remaining consumers.

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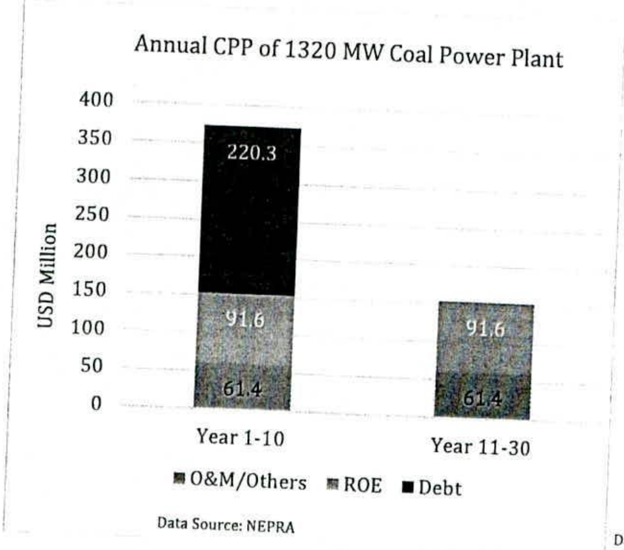
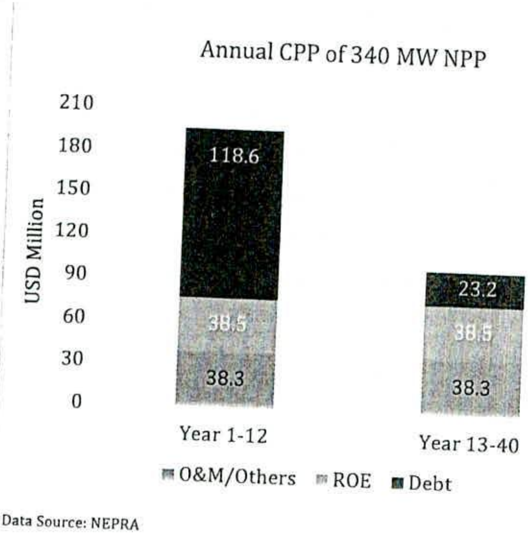
[42] Committee's projections based on net capacities

[43] CPPA-G's projections

358. Further, the front-loaded structure of ToP generation tariffs plus surplus capacity are contributing to a higher CPP component in PPP on per unit basis. While the PPA terms of power producers range from 25 to 40 years, depending on the technology in question, their tariffs are based on debt repayments of 10-12 years. This cliff-edge structure of power producers' tariff becomes a bigger problem when large capacity additions are crammed within a relatively short span of time, which is the situation presently confronting Pakistan.



Data Source: NEPRA



Data Source: NEPRA

359. As covered in Section 1, generous USD based ROEs, high cost of debt servicing, weak regulatory oversight and ToP contracts have led to enormous payments to IPPs and have added to the burdensome capacity payments. This has not only increased the cost of electricity generation but has also contributed to deepening the culture of rent seeking thereby causing much larger costs to the economy by undermining risk taking and driving resources away from other sectors.

360. Moreover, high interest spreads allowed on project debts of IPPs have enabled lenders to benefit at the expense of electricity consumers. Likewise, LPS rates are set at KIBOR + spread (up to 4.5%), while the IPPs' borrowing costs actually are much lower.

361. The box below provides a perspective on the excess setup cost of a transmission project and saving in case the tariff structure is revised to a TaP regime. This project is significant for understanding future capacity payment liabilities.

A Word of Caution - Transmission Policy 2015 & ±660 KV HVDC Project:

With the induction of medium and long-term plans of power into the national grid, the Federal Government framed the Transmission Policy 2015 for private sector participation in transmission lines infrastructure. For transmission of surplus energy to the northern region, NTDC and State Grid Cooperation of China (SGCC) signed a cooperation agreement on April 20, 2015 for development of ±660 kV 4000 MW Matiari to Lahore High Voltage Direct Current (HVDC) Transmission Line. This Project is included in the priority Projects under China Pakistan Economic Corridor (CPEC). Under the said cooperation agreement, both parties nominated subsidiary of SGCC i.e. China Electric Power Equipment and Technical Company Limited "CET" to develop the facility on BOOT basis and will also be the EPC contractor. Accordingly, PPIB approached NEPRA for award of tariff to the project requesting USD 2,119.68 million project cost. NEPRA after the end of the proceeding approved a total project cost of USD 1658.34 million in November 24, 2016.

Within the approved cost of USD 1658.34 million, USD 1,000 million was approved for converter stations. Since the project was awarded unde CPEC, through government to government agreement, hence, no bidding was carried out for award of this project. Because of lack of competition in this important infrastructure project, the first of its kind in Pakistan, it was natural to see whether the cost approved is reasonable and not excessive.

Due to budgetary constraints, a detailed global comparison with similar technology projects could not be carried out. However, it was noted that a similar project was awarded in January 2017 in India through international competitive bidding at the time when Lahore-Matiari HVDC project approvals were given. The winning bidder, ABB, a Swiss-Swedish multinational corporation headquartered in Zurich, Switzerland press release indicated that it was selected by Power Grid Corporation of India Ltd. to deliver the ±800 kV, 6,000 MW Raigarh - Pugalur Ultra-HVDC link, which will transmit power from central India to consumers in the south, a distance of 1,830 km (the longest in the World)[1]. In the agreement the convertor station cost was USD 640 million. If convertor station comparison is made on MW basis, the approved cost for the Chinese Company works out to be 2.34 times more than the ABB's bid as illustrated below:

Description	Convertor station USD million	MW	Cost per USD million/MW
Raigarh-Pugalur (1800km), India	640 million (800kv)	6,000	0.107
Lahore-Matiari(878km), Pakistan	1,000 million (660kv)	4,000	0.25
Difference			234%

It is worth highlighting that the Indian transmission line project is high in specification as well as length and is still cheaper by USD360 million. The impact of high cost of contract will be the contributing factors for high cost of energy for consumers in future due to capacity payments. The project is currently under construction therefore, it is proposed to conduct forensic audit of the project by the Federal Government, and i case of any adverse findings, get the project cost reduced to a prudent level. For future, international competitive bidding should be the most preferred route of discovery of contract prices.

Further, the HVDC project is awarded tariff under the take or pay regime. There are possibilities where the HVDC line may not be utilised as per the 98.5% approved availability because of a) outages of power plants in addition to scheduled and allowed forced outages, b) reduction in demand during off summer seasons, and c) increase in demand/consumption of Southern region, etc. As a result, the consumers will pay the capacity charges. To avoid the payment of underutilization through the fixed capacity payments, it is recommended to shift the structure of project from the current Take or Pay to Take and Pay. Depending on the utilization factor the saving over the 25 years concession period will range from PKR. 135 billion @ 90% utilization factor to PKR. 677 billion @ 50% utilization factor as detailed below:

	HVDC Utilization Factor	"Take or Pay "		"Take and Pay"		Expected savings over 25 years (Rs. billion)
		Average tariff 25 years (Rs. / kWh)	Payments Obligation (Rs. billion)	Average tariff 25 years (Rs. /kWh)	Payments Obligation (Rs. billion)	
1	100%	1.5675	1,353	1.5675	1,353	-
2	90%	1.7417	1,353	1.5675	1,217	135
3	70%	2.2393	1,353	1.5675	947	406
4	50%	3.1350	1,353	1.5675	676	677

Note: Year 1 tariff has been indexed with current USD to PKR rate of 155 and all subsequent year tariff has been projected to increase annually at 5%.

362. There are major differences amongst stakeholders with respect to the interpretation of Article 161(2) of the Constitution and the KCM[44] Methodology dealing with NHP. Despite decades of deliberations, this highly contentious issue still remains unresolved.

363. Following are some historical facts relating to NHP distribution:

- As an interim arrangement, an annual NHP payment of PKR 6.0 billion to KPK started in 1992.
- In 2005, the Federal Government formed an Arbitration Tribunal (**"AT"**) through NFC to determine the NHP amount for FY 1992 to FY 2005 (14 years). The AT gave its decision in October 2006 wherein PKR 6.9 billion NHP amount under KCM formula was indexed every year at 10% till 2005. However, no mechanism was provided for future NHP calculations.
- In February 2016, the CCI approved an MOU between the Federal Government and the Government of KPK for payment of arrears amounting PKR 70 billion to KPK in four instalments as complete settlement for past years without applying the KCM for computing NHP.
- In December 2016, the CCI approved payment of NHP to the Government of Punjab @ PKR 1.10 per unit for electricity generated from Hydel Power Station located in Punjab for years FY 2017 onwards. It also later directed payment of PKR 82 billion as arrears to the Government of Punjab.

364. As evident from the table below, total hydel levies[45] increased from PKR 7 billion in FY2015 to PKR 104 billion, which have added to the cost of electricity and in turn the circular debt problem.

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[44] In 1986, a committee headed by Mr. A.G.N. Kazi, the then Deputy Chairman Planning Commission, was established to propose a formula for calculation of NHP.

[45] Besides having NHP, hydel levies also include a small portion of IRSA charges @ PKR 0.005 per kWh payable on entire WAPDA fleets' generation and PKR 0.15 per kWh water use charge payable only on Mangla hydel plant. Both of these charges (IRSA/WUC) remained in the range of PKR 800 -1100 million demonstrating that the jump in levies are only because of NHP.

Table 50 - WAPDA: Generation, Sales Revenue and HP (Rs. Million)

	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019
WAPDA Generation (GWh)	29,326	31,204	31,525	33,151	30,797	27,121	30,937
WAPDA Sales Revenue	34,231	36,905	63,185	52,438	62,060	60,629	56,920
Hydel levies	6,831	7,015	7,110	11,978	59,265	60,529	103,790
Total Cost of WAPDA Generation	41,063	43,920	70,295	64,416	121,325	121,158	160,710
Hydel levies share	17%	16%	10%	19%	49%	50%	65%
Generation Cost (PKR/KWh)	1.40	1.41	2.23	1.94	3.94	4.47	5.19

TRANSMISSION CONSTRAINTS

365. NTDC is required to follow a regularly updated merit order for electricity dispatch listing thermal generating units in ascending order based on their variable costs. However, as highlighted by CPPA-G: "*...transmission network congestions result in dispatch of expensive generators while cheap generation remains idle owing to said constraints, thus increasing the overall energy Purchase Price for the system*".[46] Additionally, because of distribution constraints[47] and guaranteed dispatched agreed in the PPAs (e.g. RLNG), out of merit dispatch is also undertaken.

366. CPPA-G's projections of fuel mix for FY2020 suggest that generation on furnace oil would be about 5.2 billion units higher with T&D constraints than without it. Higher cost of oil-based generation increases the aggregate fuel bill of CPPA-G which is then passed on to consumers as monthly fuel charges adjustment.

Table 51 - Electricity Generation with and without T&D Constraints (FY2020)

	With T&D constraint	Without T&D constraint	Difference
Hydro	41,497	41,144	-353
Coal	21,586	25,405	3,819
FO	6,538	1,344	-5,194
Gas	14,319	23,596	9,277
Nuclear	9,019	9,168	149
Mixed	505	505	0
Import	518	518	0
Wind	3,578	3,582	4
Bagasse	1,295	1,295	0
Solar	727	725	-2
RLNG	36,360	28,660	-7,700
Total	135,942	135,942	0

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[46] https://nepra.org.pk/Admission%20Notices/2019/09-September/CPPA-G%20Report%20on%20PPP.pdf

[47] Such as low voltage, secondary transmission/transformation overloading.

367. At present, NTDC's de-rated power generation capacity is 32,767MW, whereas, the transformation capacity for 500kV and 220kV is 22,950MVA and 30,746 MVA respectively. Beside the mismatch in transmission network and power generation, NTDC requires investment in installation of grid stations and transmission if it is expected to overcome the following constraints:

i. Network constraints at some locations;

ii. Reactive power management problems resulting in voltage variations beyond permissible limits;

iii. Frequency control issues; and

iv. Underutilization of NTDC network due to DISCOs constraints.

MINIMUM PLANT FACTOR FOR RLNG BASED POWER PLANTS

368. The contractual requirements of running the 3 x 1200 RLNG based power plants at minimum 66% annual plant factor entail a higher fuel cost of electricity. The additional cost comes from:

i. Running these plants out of the merit order; or

ii. The payment required to be made up to the minimum benchmark in case the plant operates at less that 66% capacity.

369. With a significantly large share of cheaper and must run /guaranteed despatch EPP plants running on hydro, nuclear, renewable and coal, the probability of the RLNG based plants meeting the 66% plant factor on merit order is relatively low.

GAS PRICE ANOMALIES

370. With the addition of 3 x 1200 MW RLNG based power plants, the share of natural gas in total power generation increased to 41% in FY2019 from 23% in FY2015. An additional 1200 MW power plant based on RLNG, presently under construction, will start supply to the grid by mid-2020.

371. There are large variations in the price of natural gas based on its origin (domestic vs. imported LNG) and usage (residential, commercial, industry, export sector, etc.). The electricity generation sector is the biggest consumer of RLNG. In general, the

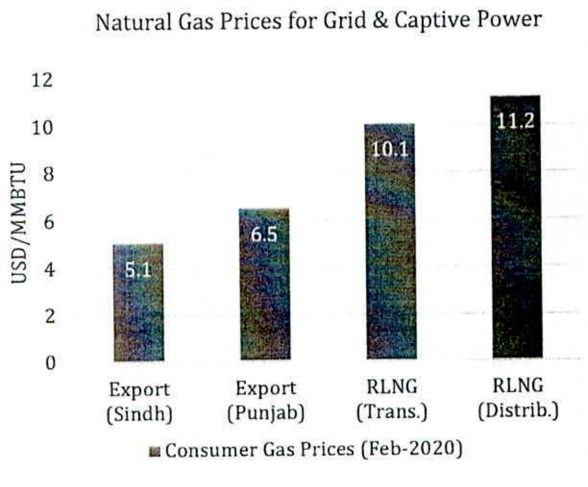
consumer price of domestic natural gas is much lower than that of RLNG[48] as the latter's pricing is set on ring-fenced basis.

372. The disparities in natural gas prices have multiple adverse effects:

i. Supply of expensive RLNG to IPPs results in higher EPP for CPPA-G;

ii. Cheaper domestic natural gas supply to captive power generation incentivises self-generation over grid electricity, which is undesirable given the large capacity surplus. Total power generation by captive power was around 13,400 GWh in FY2019, equivalent to 47% of the grid supply to the industry; and

iii. Supply of domestic natural gas to some of inefficient GENCO units puts them higher on the merit order than they would otherwise be if gas pricing was uniform.



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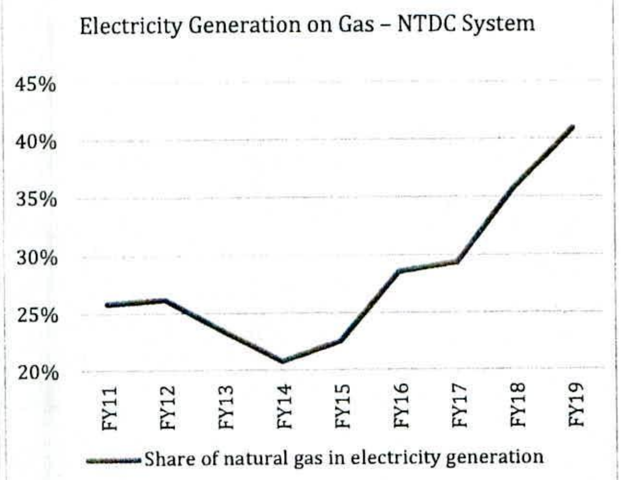

Data Source: NEPRA

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[48] Pakistan imports 800 MMCFD of LNG under Brent linked term contracts. DES price for 600 MMCFD is 13.37% of Brent while that for 200 MMCFD is 11.63%.

FINANCING COST OF CIRCULAR DEBT STOCK

373. The financing cost of the outstanding circular debt stock feeds back into even higher stock of circular debt. If an average current mark-up rate of about 15%, is assumed, the annual financing the current circular debt stock of PKR 1800 billion works out to PKR 270 billion.[49]

Distribution Inefficiencies

374. DISCOs are government owned entities, administratively working under the Pakistan Electric Power Company (**"PEPCO"**) which is headed mostly by a Government official on a part-time basis.

375. The DISCOs collectively have a country-wide customer base of 28.473 million consumers in domestic, commercial, industrial, agriculture and bulk categories, with domestic being the most dominant with 85.92% share in terms of number and 48.56% in terms of consumption. Within the domestic class, 78.13% consume electricity up to 300 units per month.

376. The second largest consumer category is industrial consumers with 25.87% share of the total sales mix. The consumption wise sales mix of different category of consumers is given below:

Table 52 - Consumption wise Sales Mix of DISCOs

Categories	**No. Of Consumers**	**Consumer Mix %**	**Sales GWh**	**Sales Mix %**
Domestic	**24,465,300**	**85.92%**	**45,590**	**48.56%**
Upto 300 units	*18,459,338*	*75.45%*	*35,619*	*78.13%*
Above 300 unit & TOU	*6,005,962*	*24.55%*	*9,971*	*21.87%*
Commercial	**3,144,247**	**11.04%**	**6,629**	**7.06%**
General Services	**178,215**	**0.63%**	**2,301**	**2.45%**
Industrial	**342,949**	**1.20%**	**24,285**	**25.87%**
Bulk Supply	**4,383**	**0.02%**	**5,082**	**5.41%**
Agriculture	**326,656**	**1.15%**	**9,676**	**10.31%**
Public Lighting	**10,567**	**0.04%**	**291**	**0.31%**
Others	**752**	**0.00%**	**33**	**0.04%**
Total	**28,473,069**	**100.00%**	**93,887**	**100.00%**

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[49] The actual mark-up charged for FY2019 amounts to PKR 95 billion as per CPPA-G's billing which does not include mark up to public sector generators. Further, the interest payments to IPPs are negotiated leading to lower LPS. About Rs. 800 billion is parked at PHPL with a mark-up of KIBOR + 80bp. Assuming KIBOR of 13.63% at June 2019 w/ 0.8% spread, the carrying cost of PHPL is Rs. 116 billion. These numbers are based on circular debt of Rs. 1,600 billion as on June 30, 2019. As circular debt has increased to Rs. 1,800 billion and LPS negotiations vary every year, carrying cost of circular debt next year will be around Rs. 270 billion.

377. While there are large variations in operational performance amongst the DISCOs, the distribution sector as a whole forms the weakest link in the country's electricity supply chain. The main reasons of operational inefficiencies of DISCOs are:

i. T&D losses;

ii. Billing under-collection; and

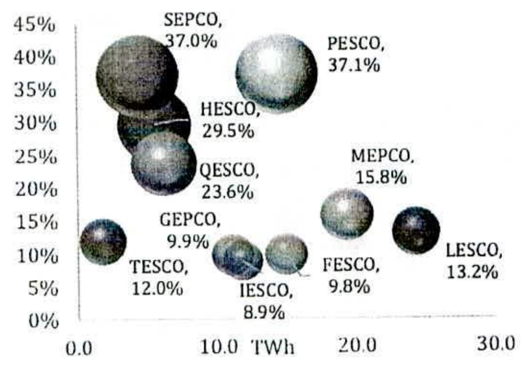
iii. Infrastructure constraints.

T&D LOSSES

378. For every 100 units of generation in the Power System during FY2019, about 3 units were lost during transmission and a further 17 units were lost due to T&D inefficiencies at the DISCO level, i.e. about 80 units were sold. The cost of 15 units lost due to system inefficiencies is allowed by NEPRA which means that the cost of only 2 units is borne by the DISCOs. At the billing level, the system is further burdened with 9% under recoveries. This translates to a loss of Rs. 32 billion due to T&D's inefficiencies and an additional loss of Rs.120 billion[50] due to under recovery.

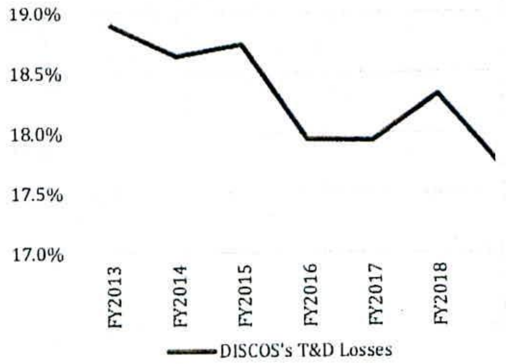
379. As shown in the charts below, the disaggregated data reveals large variations in T&D losses across DISCOs with lowest of 8.9% for IESCO and highest of 37% for PESCO and SEPCO. Clearly, size (in terms of coverage area and/or units purchased) is not a determinant of T&D losses. SEPCO is only 1/5th the size (units purchased) of LESCO while its T&D losses are 2.8 times as high as LESCO's.

T&D Losses – By DISCOS (Units Purchased)



Data Source: PEPCO

DISCOS' T&D Losses



Data Source: Energy Yearbooks, NEPRA

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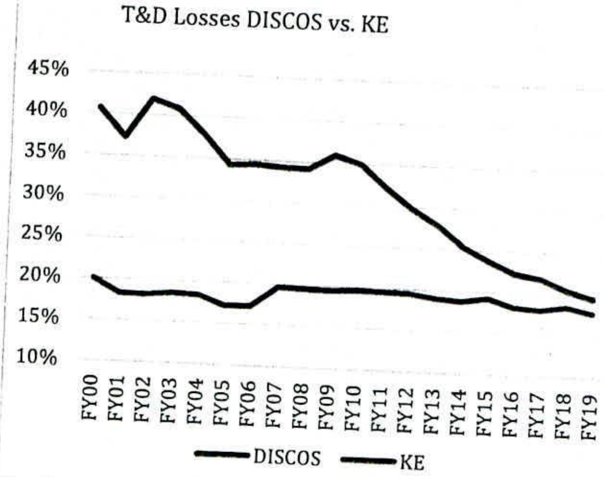
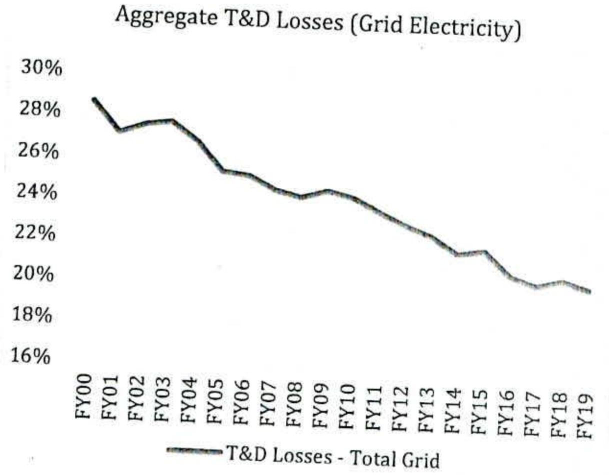
[50] The impacts have been calculated using weighted average rates applicable during FY 2019.

380. The evidence from KE suggests that with governance improvements and investment, there is scope for significant reduction in DISCOs' T&D losses. KE's T&D losses halved from over 40% in FY2000 to ~20% in FY2019 as show in the chart below. Over the same period, DISCOs' aggregate T&D losses have shown a more modest reduction of 230bp, from 20% in FY2000 to 17.7% in FY2019.



T&D Losses DISCOS vs. KE

Data Source: PEPCO



Aggregate T&D Losses (Grid Electricity)

Data Source: Energy Yearbooks, NEPRA

381. Presentations by operational teams of various DISCOs revealed the following reasons for their technical and administrative losses:

- Over loading of secondary transmission & distribution system is badly affecting the quality of supply to consumers, contributing to increase in technical losses;
- Lengthy 132 & 66 kV transmission lines, lengthy 11 kV feeders and off-size 11 kV conductor;
- Substandard electrification of villages, new connections being given on political grounds and malpractices of employees of DISCOs increase technical losses, eventually leading to excess cost of system rehabilitation and loss reduction;
- Illegal abstraction of electricity through hooks, tampering of meters, etc. For example, in SEPCO, as per a tentative survey there are more than 400,000

illegal connections. Further, the administration is inefficient regarding timely replacement of defective meters and monitoring/surveillance of network;

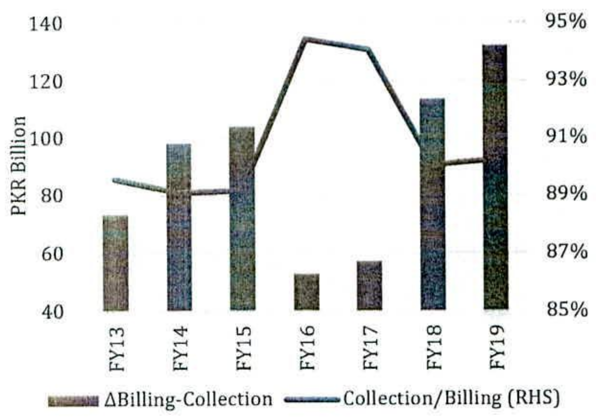
- There is prevalent culture of unmetered supply and non-payment in some areas, without support from local law enforcement; and
- Financial liabilities on account of disputed arrears pending stays given by Courts.

BILLING UNDER-COLLECTION

382. Another issue for DISCOs is under-collection of amounts billed to customers. Their overall collection/billing ratio averaged around 91% over the past 7 years (FY2013-FY2019). The cumulative shortfall in collections over billing during this period amounted to PKR 633 billion of which FY2019 alone accounted for PKR 132 billion.

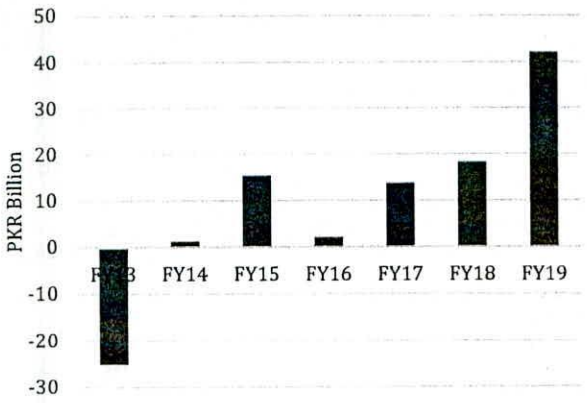
383. The shortfall in collections from customers impairs the ability of DISCOs to meet their obligations towards CPPA-G which further deepens their cash flow deficits by payment of taxes on uncollected bills. KE also falls behind in payments to CPPA-G for electricity purchased from the NTDC System. CPPA-G's receipts from KE in FY2019 were PKR 42.4 billion lower than the amount billed during the year.

DISCOS' Bill Collection



Data Source: PEPCO

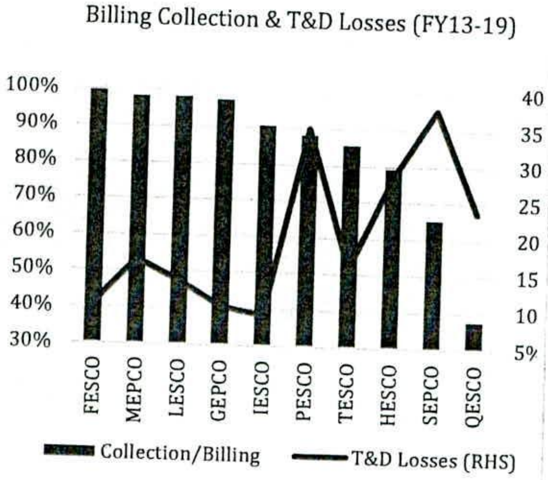
CPPA-G's Billing minus Collection from KE



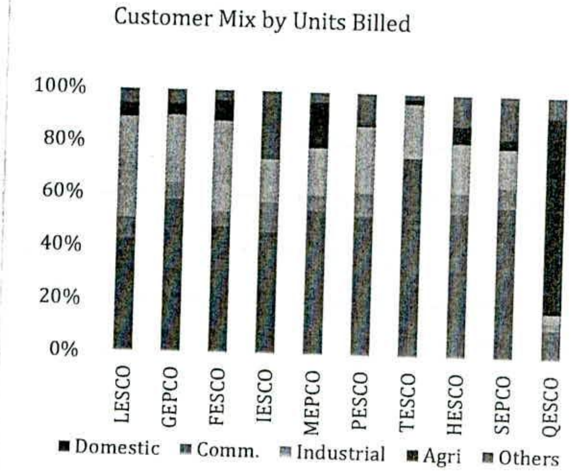
Data Source: PEPCO

384. As with the T&D losses, the collection/billing ratio varies substantially across DISCOs. Over the last 7 years (FY2013-19), the average collection ratio for individual DISCOs ranged from nearly 100% at the higher end to less than 40% at the bottom of the

table. Unsurprisingly, the DISCOs with lower T&D losses generally have higher collection rates and vice versa.


Billing Collection & T&D Losses (FY13-19)

Data Source: PEPCO


Customer Mix by Units Billed

Data Source: PEPCO

385. DISCOs' receivables from private sector defaulters amounted to PKR 628 billion at end of Dec-2019, comprising PKR 525 billion due from running defaulters and PKR 103 billion recoverable from disconnected (permanent) defaulters. More than 87% of the amount recoverable from running defaulters and around 84% of that from disconnected defaulters is overdue for more than 3 years. Also worrying is the unbridled growth in the amounts due from running defaulters who continue to receive electricity despite non-payment. The increase in these amounts creates doubts if they represent disguised T&D losses (excess billing) or genuine billing.

Table 53 - Break-down of Power Sector Receivables (PKR Million)

	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18	Jun-19	Dec-19
Total Receivables	**512,909**	**633,119**	**684,057**	**729,881**	**896,146**	**1,145,004**	**n.a.**
Government	**129,047**	**155,545**	**169,082**	**115,016**	**146,837**	**193,377**	**206,423**
- Federal	6,097	5,333	4,001	4,882	7,196	13,718	17,089
- AJ&K	37,969	53,123	65,465	80,746	99,266	126,768	127,060
- Provincial	84,980	97,089	99,617	29,388	40,376	52,892	62,274
Private	**355,630**	**433,582**	**468,715**	**554,785**	**670,706**	**856,882**	**836,390**
- Running Defaulters	234,075	303,025	318,495	351,551	404,840	476,934	524,550
- Disconnected Defaulters	44,632	49,967	57,594	77,643	95,352	95,248	103,202
- Spill Over	36,702	40,202	38,810	44,564	55,383	70,271	56,240
- Deferred Amount	6,597	13,224	7,469	21,319	22,480	23,668	28,241
- Instalments	10,027	9,093	9,188	1,485	1,948	1,453	2,679
- Subsidies	26,455	22,093	41,970	64,562	97,474	196,268	121,478
- Unidentified	-2,858	-4,021	-4,811	-6,339	-6,772	-6,960	-6,070
K-Electric	**28,204**	**43,974**	**46,235**	**60,070**	**78,396**	**91,734**	**n.a.**
IPPs	**28**	**18**	**25**	**10**	**206**	**3,010**	**n.a.**

386. Of the total Rs. 525 billion due from running defaulters at Dec-2019, QESCO accounted for nearly 48.7%, followed by SEPCO (17.6%), PESCO (11.4%), HESCO (11.1%) and TESCO (8.7%). As for the Rs. 103 billion recoverable from disconnected defaulters at Dec-2019, PESCO had the lion's share at 45.3%, followed by HESCO (14.4%), SEPCO (13.7%) and LESCO (13.1%).

Table 54 – DISCO Wise Amounts Due from Running and Disconnected Defaulters

	Running Defaulters		**Disconnected Defaulters**	
	PKR Million	**%Total**	**PKR Million**	**%Total**
LESCO	6,809	1.3%	13,520	13.1%
GEPCO	1,080	0.2%	719	0.7%
FESCO	1,444	0.3%	832	0.8%
IESCO	1,058	0.2%	344	0.3%
MEPCO	2,304	0.4%	6,629	6.4%
PESCO	60,003	11.4%	46,742	45.3%
HESCO	58,434	11.1%	14,887	14.4%
SEPCO	92,466	17.6%	14,186	13.7%
QESCO	255,565	48.7%	1,959	1.9%
TESCO	45,387	8.7%	3,384	3.3%
TOTAL	**524,550**		**103,202**	**3.3%**

INFRASTRUCTURE CONSTRAINTS

387. Power delivery through DISCOs' networks mainly depends on the adequacy of transformation system (132/11kV transformers), 11kV feeders (circuits) and finally the distribution transformers and low voltage circuits. Overloading of secondary transmission and transformation system, distribution lines and transformers are serious threats to the sustainability and quality of power supply.

LOADING POSITION OF POWER TRANSFORMERS

388. Loading capacity of power transformers should ideally be kept at 80% for optimal utilization, beyond which it is categorized as overloaded power transformer. It was observed that out of 2025 transformers among all DISCOs, 23.01 % were overloaded in FY 2017-18. Worst performers were PESCO, HESCO and SEPCO with 52.97%, 40.50% and 38.89% respectively having overloaded transformers. IESCO and LESCO had only 0.81% and 3.59% of their transformers overloaded.

LOADING POSITION OF 11 KV FEEDERS (CIRCUITS)

389. Overloading in feeders increases the losses as well as frequent interruptions in power supply besides low voltages at consumer end. Overloading (above 80% utilization) on 11kV feeders stood at 23.49% in FY 2017-18 across country-wide 8850 feeders. TESCO's position was the worst with astounding 100% of its 11 kv feeders overloaded followed by PESCO at 40.71%, SEPCO at 32.04% and QESCO at 32.56%.

LOADING POSITION OF DISTRIBUTION TRANSFORMERS

390. Overloading of distribution transformers results in damage of transformers and long duration of interruptions of supply to consumers. There were 13,292 damaged distribution transformers in all DISCOs in FY 2017-18. Out of total 708,761 distribution transformers, 32,242 are overloaded beyond 80%. The DISCO wise loading position is given below:

Table 55 – Loading Position of DISCO Transformers

Name of DISCOs	Power Transformer	11 Kv feeders	Distribution Transformers	Overloaded Power Transformer		Overloaded 11 Kv feeders		Overloaded Distribution Transformers		No of Damaged Transformers
PESCO	236	1,012	74,104	125	53.0%	412	40.7%	6,183	8.3%	2,524
TESCO	38	207	18,475	14	36.8%	207	100.0%	--	--	--
IESCO	248	1,068	47,830	2	0.8%	25	2.3%	3,770	7.9%	1,246
GEPCO	174	835	64,344	51	29.3%	59	7.1%	1,741	2.7%	1,741
LESCO	390	1,741	105,185	14	3.6%	417	24.0%	2,950	2.8%	2,414
FESCO	225	1,023	104,058	42	18.7%	149	14.6%	392	0.4%	1,595
MEPCO	292	1,324	161,197	65	22.3%	373	28.2%	5,844	3.6%	2,558
HESCO	121	502	36,670	49	40.5%	69	13.8%	532	1.5%	293
SEPCO	126	490	37,562	49	38.9%	157	32.0%	3,736	10.0%	483
QESCO	175	648	59,336	55	31.4%	211	32.6%	7,094	12.0%	438
Total	**2,025**	**8,850**	**708,761**	**466**	**23.01%**	**2,079**	**23.49**	**32,242**	**4.55%**	**13,292**

PROVINCE-WISE NETWORK ANALYSIS OF DISCOS

391. Following is a province-wise comparison of the overloading position for FY 2017-18:

Table 56 - Province Wise Network Analysis

Description	Punjab	Sindh	KPK	Baluchistan	Total
No. of 132 kV Grid Stations	518	124	91	69	**802**
Total No. of Power Transformers	1,329	247	274	175	**2,025**
Over-Loaded Power Transformers (Nos.)	174	98	139	55	**466**
Over-Loaded Power Transformers (%)	**13.09**	**39.68**	**50.73**	**31.43**	**23.01**
Total No. of 11 kV Feeders	5,991	992	1,219	648	**8,850**
Over-loaded 11 kV Feeders (Nos.)	1,023	226	619	211	**2,079**
Over-loaded 11 kV Feeders (%)	**17.07**	**22.78**	**50.78**	**32.56**	**23.49**
Total No. of Distribution Transformers	482,614	74,232	92,579	59,336	**708,761**
Over-loaded Distribution Transformers (Nos.)	14,697	4,268	6,183	7,094	**32,242**
Over-loaded Distribution Transformers (%)	**3.04**	**5.75**	**6.68**	**11.96**	**4.55**

Regulatory and Fiscal Inefficiencies

392. The following factors in combination contribute significantly to the build-up of circular debt:

    a. Delays in tariff determinations and notifications due to legal challenges and political considerations;

    b. Under-budgeted tariff subsidies and their slow disbursements; and

    c. Tax refund claims.

393. While all DISCOs are adversely impacted by the fiscal ambiguities and tax drag, IESCO and QESCO are the biggest victims. At end Dec-2019, IESCO had Rs. 88.5 billion in outstanding receivables from the government of AJK while QESCO had Rs. 19.4 billion receivable from the provincial government and another Rs. 37.2 billion in tariff subsidies due from the Federal Government. IESCO's receivables from the government of AJK reflect the differential amount based on notified tariff and the tariff at which the government of AJK has been making the payments. As for QESCO, unpaid subsidies on agriculture tube-wells is the main issue.

394. KE's trade receivables from government and autonomous bodies amounted to Rs. 43.5[51] billion at end of FY2018, which is the latest year for which its financial statements are available. In addition, the company had Rs. 49.3 billion in tariff subsidies due from the Federal Government. KE's payables towards CPPA-G, SSGC and PSO amounted to Rs. 87.5 billion (which rose to Rs.135 billion for FY2019), Rs.18.8 billion and Rs.2.4 billion at end FY2018.

395. The taxation regime is also a significant drag on DISCOs' cash flows. The companies carry large refund/input adjustment claims of sales tax and other government levies on their balance sheets. The problem is even bigger for DISCOs that have lower bills collection but have to pay taxes even on uncollected/defaulted electricity bills. For example, QESCO had gross amount of Rs. 37.7 billion as duties/charges and tax receivables on its balance sheet at end FY2018 against which it had made provision for doubtful receivables amounting to Rs. 17.8 billion.

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[51] This the principal amount only. An additional Rs. 6.5 billion showed as LPS receivable from these entities.

WAY FORWARD - CIRCULAR DEBT & DISTRIBUTION INEFFICIENCIES

396. This section lays out specific measures to address the fundamental causes of the circular debt problem along with suggested reforms for the distribution segment of the power sector.

397. Altogether, they can become part of a circular debt resolution plan that meets two essential criteria of sustainability:

i. How to achieve retirement of existing circular debt stock; and

ii. How to stem the flow of circular debt.

Dealing with the Existing Stock of Circular Debt

398. The annual financial cost[52] of the outstanding stock of Rs. 1,800 billion at Dec-2019 works out to nearly PKR 270 billion (around PKR 2.7/KWh based on total units billed in the power system during FY2019) at current mark-up rate of almost 15%.

399. Given the binding constraints of a weak fiscal position, already high consumer-end electricity prices and rising cost of generation, out-of-the-box solutions are required to eradicate the existing circular debt stock or at least minimize its ongoing financial drag. The following are proposed measures for dealing with the existing circular debt stock.

RECOVERING RECEIVABLES FROM THE GOVERNMENT AND KE

400. The table below shows the DISCOs' gross receivables position at end Dec-2019. As against the outstanding circular debt stock of Rs. 1,800 billion, total DISCO receivables amounted to Rs. 1,131 billion. Rs. 419 billion of this is recoverable from the Federal and Provincial Governments, as well as KE which can be immediately paid and used toward reducing the outstanding circular debt stock parked in PHPL in order to reduce the interest payments to banks.

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[52] The amounts on PHPL's books carries mark-up rate of KIBOR + 80bp while the rate of LPS on overdue payables on CPPA-G-G's books is up to KIBOR + 4%.

Table 57 - DISCOs' Receivables at end Dec-2019 (Rs. Million)

	PKR MN	%Total
Total Receivables	**1,131,488**	**100.0%**
Government	206,423	18.2%
- Federal	17,089	1.5%
- AJ&K	127,060	11.2%
- Provincial	62,274	5.5%
Private	830,320	73.4%
- Running Defaulters	524,550	46.4%
- Disconnected Defaulters	103,202	9.1%
- Spill Over	56,240	5.0%
- Deferred Amount	28,241	2.5%
- Instalments	2,679	0.2%
- Subsidies	121,478	10.7%
- Unidentified	-6,070	-0.5%
K-Electric	91,734	8.1%
IPPs	3,010	0.3%

FORENSIC AUDIT AND SETTLEMENT WITH IPPS

401. As covered in Section 1, a detailed forensic audit may be conducted in order to establish the true set-up and operational costs of IPPs leading to a comprehensive settlement package entailing:

i. Recovery of excess payments made so far;

ii. Conversion to rupee based revised tariffs;

iii. Elimination of ToP contracts;

iv. Extension of repayment period of project debts along with reduction in interest rates thereon; and

v. Reducing LPS rate with retrospective effect, etc.

402. The total savings relating to the past periods would yield reduction in the outstanding stock of circular debt.

BURDEN SHARING WITH PROVINCES

403. Electricity is included in Part II of the Federal Legislative List, which falls under the jurisdiction of the CCI. However, as noted by the IMF[53] in July 2017 Country Report, '*The [7th] NFC's report did not consider critical functions of national importance, which fall under the jurisdiction of the CCI - and hence joint responsibility of the*

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[53] IMF Country Report 17/213, July 2017. Pakistan: Selected Issues

federal and provincial governments - after the 18th Amendment. Most importantly, such areas include public debt and the electricity sector, which pose considerable claims on public finances.'

404. In the section on considerations for the next NFC Award, the IMF report suggested that 'provinces' participation in reforming the power distribution sector as well as sharing the burden of liabilities arising from delays with such reforms should be considered.' A mechanism may therefore be devised for sharing the burden of electricity subsidies and the outstanding amount of circular debt between the centre and the provinces.

INTRODUCING ADDITIONAL PETROLEUM LEVY

405. Petroleum Levy is the tax which belongs exclusively to the Federal Government. Taking advantage of lower international oil prices, an additional petroleum levy can be introduced on transportation fuels i.e., petrol and diesel, and the amounts collected used toward retirement of circular debt stock. With aggregate annual consumption of 20 billion litres of petrol and diesel, a Rs. 5 per litre charge would generate Rs. 100 billion in additional revenues per year.

RE-FINANCING CIRCULAR DEBT

406. Eliminating the outstanding stock of circular debt is critical to stopping its further build-up. Any leftover amount after recoveries of DISCOs' receivables and settlement with IPPs need to be removed from the books of CPPA-G and PHPL as they entail a heavy financial cost.

407. The net stock of the circular debt may need to be absorbed into the public debt. However, history suggests that such stock settlement of outstanding amounts induces a sense of complacency at both political and institutional levels, which eventually result in relapse of the problem with even bigger magnitude. It is therefore critical that any settlement of principal amounts becomes part of a comprehensive plan which ensures that circular debt flow is also stopped while stock is eliminated.

408. A one-time increase in public debt to remove the stock can be linked with quantifiable KPIs and an accountability mechanism whereby future savings due to

reduced cost of generation and other measures outlined above are used to pay back this increase.

409. To minimise the fiscal cost of removing the outstanding stock from CPPA-G/PHPL books, different structures may be evaluated. These could include, among other options:

- i. A cash settlement from budget (either as subsidies or though capital injection into DISCOs);
- ii. The issuance of long-term non-interest-bearing government securities to creditors; or
- iii. Some form of concessional refinancing by SBP.

410. The SBP extends re-financing to banks for exports and other priority sectors at 2% for short-term and 3% for long-term loans. The total amount of financing to banks under various schemes amounted to PKR 578 billion at end Jun-2019. The repayment/servicing of the amount of circular debt transferred to the SBP's books could be from retention of 20% profits by SBP before any transfers to the federal government.

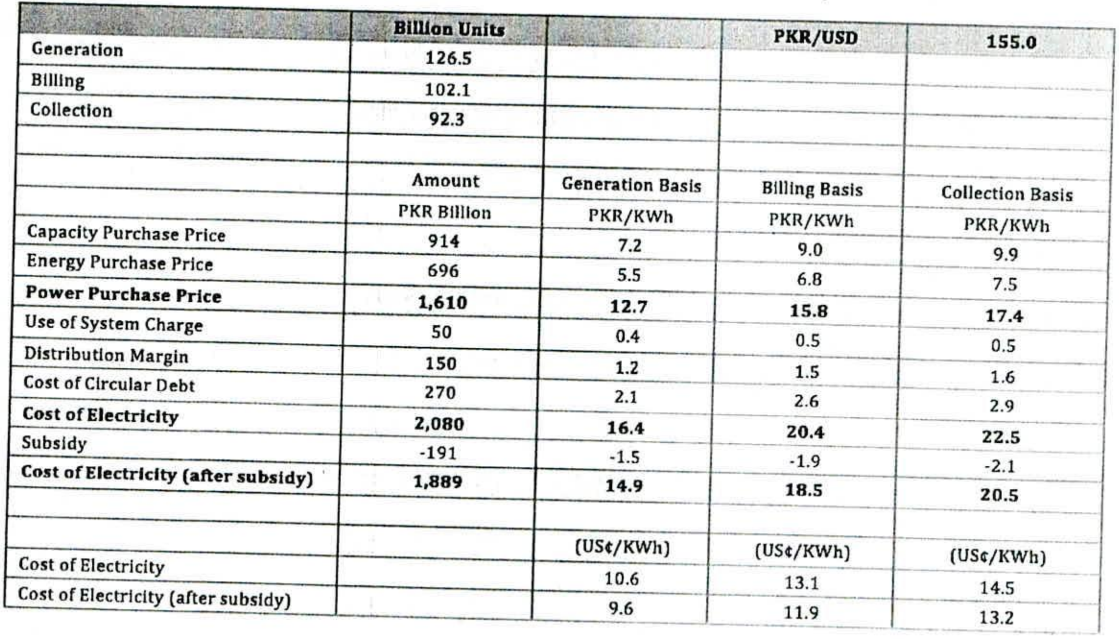
Stemming the Flow of Circular Debt

HIGH COST OF GENERATION

411. The table below provides break down of the estimated cost of electricity supply for FY2020. The three variants of cost of electricity per unit presented in the table are based on:

- a. Units generated;
- b. Units billed; and
- c. Units for which bill collection takes place.

Table 58 – Estimated Cost of Electricity FY2020



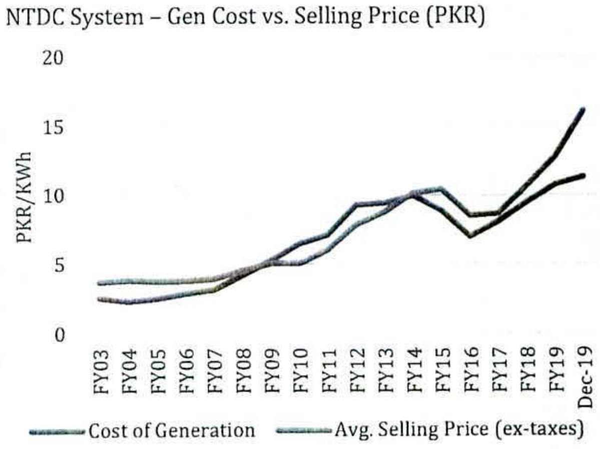
	Billion Units		PKR/USD	155.0
Generation	126.5			
Billing	102.1			
Collection	92.3			
	Amount	Generation Basis	Billing Basis	Collection Basis
	PKR Billion	PKR/KWh	PKR/KWh	PKR/KWh
Capacity Purchase Price	914	7.2	9.0	9.9
Energy Purchase Price	696	5.5	6.8	7.5
Power Purchase Price	**1,610**	**12.7**	**15.8**	**17.4**
Use of System Charge	50	0.4	0.5	0.5
Distribution Margin	150	1.2	1.5	1.6
Cost of Circular Debt	270	2.1	2.6	2.9
Cost of Electricity	**2,080**	**16.4**	**20.4**	**22.5**
Subsidy	-191	-1.5	-1.9	-2.1
Cost of Electricity (after subsidy)	**1,889**	**14.9**	**18.5**	**20.5**
		(US¢/KWh)	(US¢/KWh)	(US¢/KWh)
Cost of Electricity		10.6	13.1	14.5
Cost of Electricity (after subsidy)		9.6	11.9	13.2

412. The key assumptions underlying the above table are:

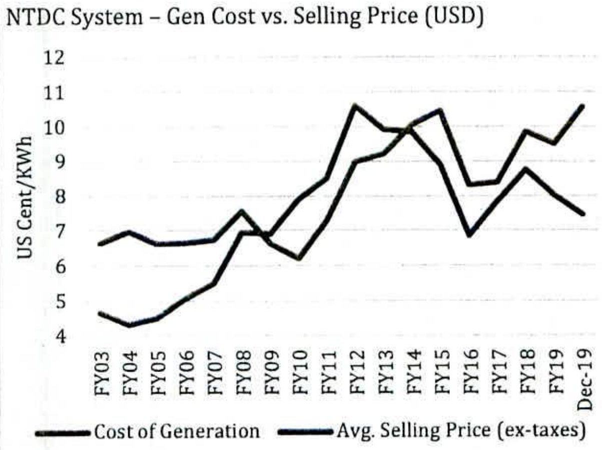
- Generation of 126.5 billion units based on 3% growth over FY2019.
- Units billed is 80.7% of generation (based on actual levels for FY2019).
- Units on collection basis is 73% of generation (under recoveries at ~10% based on actual levels for FY2019).
- CPP of PKR 914 billion is CPPA-G's forecast for FY2020.
- EPP is based on CPPA-G's forecast of EPP/Unit of PKR 5.5 for FY2020.
- Use of System charge and Distribution Margin are based on actual FY2019 values adjusted for inflation.
- Cost of circular debt is at 15% of current stock of PKR 1,800 billion.
- Subsidy of PKR 191 billion is actual budgeted figure for FY2020.

413. As evident from the above table, an average consumer tariff (excluding taxes) of PKR 20.5/KWh (US¢ 13.2/KWh) for FY2020 would be required for recovery of all direct and indirect costs of electricity supply, assuming that demand remains inelastic to

further increase in tariffs. This is 26.5% higher than the DISCOs' average sale rate of PKR 16.3/KWh[54] (US¢ 10.5/KWh) for Dec-2019.



Data Source: NEPRA, PEPCO



Data Source: NEPRA, PEPCO

414. The electricity tariffs are already at record highs in both PKR and USD terms as evident from the above charts and further increases would be unsustainable. It is therefore imperative to reduce the cost of electricity generation. The following paragraphs explain a number of remedial measures that can help bring down the cost of electricity and stem the flow of circular debt.

CAPACITY PAYMENTS

RE-PROFILING CAPACITY PAYMENTS

415. This aspect was touched upon briefly in the Way Forward part of Section 1, however, it is covered here with the objective of highlighting measures beyond the review of IPP contracts.

416. Debt servicing accounts for nearly 50% of the total CPP in FY2019, followed by ROE with a share of 30% while fixed O&M/other costs account for only 20%. Out of the total CPP of PKR 640 billion in FY2019, the share of public sector generators (WAPDA, GENCOs, NPPs and government owned IPPs) comprised PKR 318 billion or almost 50%. In addition to the under-construction power projects in the private sector, a number of large projects are at advanced stages of completion and will be

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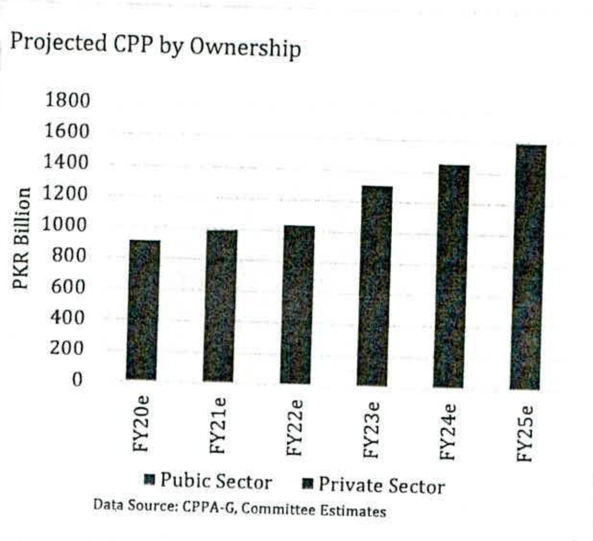
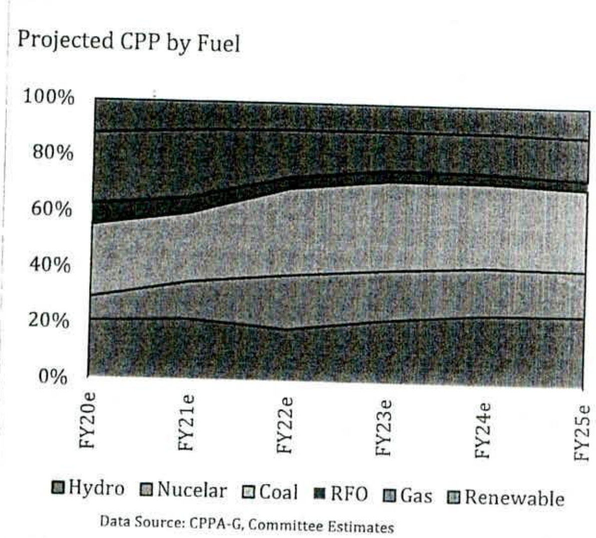
[54] DISCOs performance statistics: Dec-2019

commissioned between 2020 and 2023 including 2 x 1100 MW NPPs (KANUPP 2 & 3), 1200 MW 4th RLNG based IPP and 2 x 660 MW coal fired plant of Jamshoro Power (GENCO-I). Therefore, the share of public sector in total CPP shall continue to range between 45-50% over the next 5 years.

417. While the total annual capacity payment bill has already snowballed from PKR 275 billion in FY2016 to PKR 640 billion in FY2019, CPPA-G projects it to increase to almost PKR 1,600 billion in FY2025. In terms of fuel source of plants, the combined share of hydro, nuclear and coal-fired power plants in aggregate CPP would range between 60-70%.


Projected CPP by Ownership

Data Source: CPPA-G, Committee Estimates


Projected CPP by Fuel

Data Source: CPPA-G, Committee Estimates

418. The following provides a perspective about the contribution of different clusters of power plants to current and future total CPP:

Four NPPs (CHASNUPP 1-4)

- CPP at aggregate net capacity of 1230 MW = PKR 71 billion in FY2019.
- Addition of 2 x 1100 MW NPPs in 2020-21 (KANUPP 2 & 3) would increase aggregate to about PKR 325 billion.
- External debt of the NPPs has repayment periods of 12 years while PPA terms are 40 years and actual plant lives are even longer.

WAPDA

- Total CPP was PKR 161 billion in FY2019.
- With commissioning of Neelum Jhelum hydropower project and Tarbela-IV, the annual CPP of WAPDA will be close to PKR 200 billion even as NHP arrears run-off completely.

Coal Fired

- Total CPP amounted to PKR 82 billion in FY2019.
- Annual figure would increase to more than PKR 400 billion in the next 3 years as more coal-based capacities are commissioned.

RFO Plants

- Total CPP of the 11 RFO-only power plants would continue to stay above PKR 60 billion a year.

419. Though the Government should immediately start work on coming out of all ToP arrangements and move towards TaP contracting as suggesting in Section 1, it needs to act immediately on:

- Imposing a moratorium whereby no new power plants come online for the next few years. The exception would be the conversion of existing wind farms into hybrid wind-solar model with the aim to improve system stability, address intermittency and lower overall tariffs;
- Not renewing the contracts of plants reaching expiry;
- Extending the debt repayment periods of power producers and re-adjusting their tariffs accordingly. A bigger near-term relief in CPP would result from deferral of principal repayments for a period of 3 years;
- Reducing the spreads over KIBOR/LIBOR for the long-term project debts;
- Lowering the spreads over KIBOR for LPS; and
- Retirement of older/inefficient GENCOs.

420. A combination of these measures can immediately help reduce annual CPP burden by Rs. **150-200 billion**, helping reduce power tariff by **Rs. 1/KWh.**

MAKING KE PART OF THE SOLUTION

421. Against a peak demand of over 3500 MW, the total capacity of the KE System is 2900 MW including KE's own fleet of 2300 MW and 600 MW contracted from IPPs and other power plants. KE also gets 650 MW directly from the NTDC System and another 150 MW from CPPA-G contracted wind power projects.

422. About 1550 MW of KE System's generation capacity (including 1300 MW of its own fleet and two RFO based IPPs of 250 MW) is old and inefficient. KE is planning to setup two major imported fuel-based power projects including 900 MW RLNG based and 700 MW coal fired plants.

423. However, KE can help absorb the surplus capacity of the CPPA-G' contracted capacity by taking an increased supply of electricity directly from the NTDC network and/or novation of PPAs of some CPPA-G's contracted new coal based IPPs located near Karachi.

424. There have been significant additions of power generation capacities in the southern part of the country including 2640 MW imported coal-based plants, 660 MW Thar coal power plants and several wind farms. Moreover, another 4,120 MW power plants presently under construction including 2200 MW NPPs, 1320 MW coal-based projects and 600 MW WPPs, would be commissioned within the next 24 months and more power plants shall be added in the subsequent few years.

425. As the government pursues its policy of power sector deregulation with shift towards wholesale competitive markets and separation of distribution and supply businesses, a more integrated national grid system would be required. A detailed technical study on integration of NTDC and KE Systems must be carried out in increasing the supply from NTDC to KE grid.

426. This would also identify any network constraints prohibiting to meet the required demand of KE from NTDC system which could warrant capital expenditure to be financed by NTDC and/or KE depending on the geographical/network jurisdiction.

427. However, the capex for improvement of the existing network, let alone the time to complete such improvements, is going to be relatively low compared to building of new power plants to meet the same demand. In the latter, tariff would involve an attractive fixed return, a high debt cost and a NEPRA approved ToP tariff regime. Therefore, ideally, KE should halt generation expansion projects until that study is completed. KE system with under capacity can thus help reduce the impact of capacity payment in the over supplied national grid by selling excess power to KE subject to commercially agreed terms.

INCENTIVISING INDUSTRY'S SWITCH FROM CAPTIVE POWER TO GRID ELECTRICITY

428. Natural gas is the predominant fuel for captive power generation although coal, biomass and solar PV are also gaining traction as fuel sources for self-generation. Cost and reliability are the two main factors for the industry's preference of captive power over the grid. Captive power generation is cheaper than grid electricity and its supply is reliable (i.e., uninterrupted and stable). Moreover, the cost advantage of captive power is even bigger for industries such as composite and value-added

textile units, which use combined heat and power to meet their twin requirements of steam and electricity.

429. The table below shows a comparison of electricity cost from captive power generation (on natural gas) versus grid electricity for the export-oriented industry or that supplying to the domestic market.

Table 59 - Cost of Electricity: Captive Power vs. Grid Electricity

Province		**Punjab**	**Sindh/KP**	**Punjab**	**Sindh/KP**
Type of Industry		Export	Export	Domestic	Domestic
Gas price	PKR/MMBTU	1,008	786	1,736	1,021
PKR/USD		155	155	155	155
Gas price	USD/MMBTU	6.5	5.1	11.2	6.6
Thermal Efficiency (LHV)		40%	40%	40%	40%
Fuel Cost	PKR/KWh	9.5	7.4	16.4	9.7
Other Costs	PKR/KWh	1.5	1.5	1.5	1.5
Captive Tariff	**PKR/KWh**	**11.0**	**8.9**	**17.9**	**11.2**
Grid Tariff	**PKR/KWh**	**11.6**	**11.6**	**18.2**	**18.2**
Grid/Captive		5%	30%	2%	63%
Captive Tariff	**US¢/KWh**	**7.1**	**5.8**	**11.6**	**7.2**
Grid Tariff	**US¢/KWh**	**7.5**	**7.5**	**11.8**	**11.8**

430. Two take-aways from this table are:

a. Captive generation is cheaper than comparable grid tariff; and

b. There are large regional disparities in natural gas prices for same consumer categories.

431. While Pakistan's export industry supports the electricity tariff of US¢ 7.5/KWh as regionally competitive, captive generation remains cheaper at current natural gas prices and the cost advantage is much bigger for the industry in Sindh/KPK. For the industry serving domestic markets, captive generation is slightly cheaper even at currently high RLNG prices (in Punjab) as the comparable grid electricity tariff is very high.

432. Further, SNGP accounts for 60% of the natural gas supply to captive power while the rest 40% is by SSGC. Majority of the captive power plants on SSGC network are located in and around Karachi and hence fall under the KE's service area.

Table 60 - Captive power generation in service areas of the two public grid systems

Electricity Sales from NTDC System to Industry	GWh	24,285
Total Electricity Sales from NTDC System	GWh	93,887
Gas supplied to captive power from SNGP	BBTU	75,164
Estimated generation by captive power	GWh	7,938
Captive Power/Supply to Industry from NTDC System		32.7%
Captive Power/Total from NTDC System		8.5%
Sale from KE System to Industry	GWh	4,248
Total Sale from KE System	GWh	14,276
Gas supplied to captive power from SSGC	BBTU	51,658
Estimated generation by captive power	GWh	5,456
Captive Power (SSGC)/Supply to Industry from KE System		128.4%
Captive Power (SSGC)/Total from KE System		38.2%

433. The KE System has a net capacity deficit and imports 650 MW from the NTDC System, while the KE-NTDC transmission link is already operating at maximum capacity. Realistically, only the industry receiving gas supply from SNGP for captive power generation can shift to the NTDC system, which has surplus capacity. Assuming all captive power plants on SNGP network shift to the grid, it would increase total generation by 6.3% and bring down per unit CPP by 3.3%.

434. The following factors need to be considered while rationalising the energy prices (gas and electricity) for the industrial sector:

- The natural gas price for the export industry may be set at a level such that their grid tariff becomes at least 5% cheaper than captive generation (at 40% single cycle thermal efficiency).
- The grid tariff for manufacturing industry needs downward adjustment not only to attract back industry using captive generation but also to pre-empt future grid defection.
- Uniform natural gas prices for same category of industrial customers may be considered across the country with no regional disparities.

435. In addition to energy price rationalisation, removal of electricity supply constraints (transmission and distribution) is critical to encouraging shift of the industry using captive power to the grid.

ELECTRIFICATION OF ENERGY USE

436. The global energy sector is undergoing unprecedented transformation due to rapid advancements in technology, making electricity cheaper and greener. This is driving the substitution of fuels such as oil and gas with electrification of final energy consumption e.g. electric vehicles (EVs), space/water heating and cooking – the needs that were traditionally served by hydrocarbons.

437. Pakistan's energy[55] imports amounted about USD 16.0 billion in FY2019, accounting for almost 30% of the country's total imports. In this scenario, electricity can meet our energy needs more efficiently and yield multiple benefits including a higher base load, lowered cost of electricity and higher overall energy efficiency. Moreover, import substitution of energy through increased reliance on domestic resources (renewable and coal) would add to the country's GDP growth.

438. Oil and gas consumption in domestic (6.655 MTOEs), commercial (2.001 MTOEs) and transport (18.637 MTOEs) sectors collectively amounted to 27.2 MTOEs in FY2018[56], which was more than 3 times the amount of energy consumed as electricity in the country in equivalent MTOEs of 8.708. Shifting even a small fraction of energy consumption in transportation, space/water heating and cooking to electricity (from oil, gas, LPG, etc.) would greatly increase the country's electricity consumption, thereby lowering the cost of power generation.

439. These factors should be considered as part of holistic planning including new variables such as distributed solar plants, expected demand of EVs, energy efficient appliances, the potential impact of shift of load to captive power from grid and the sale of power to bulk power consumers through wheeling. Moreover, the load shedding carried out by DISCOs on feeders with high Aggregate Technical and Commercial ("**AT&C**") losses also needs to be considered at the time of demand forecast.

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[55] Oil, LNG and Coal

[56] Energy Yearbook 2018

NHP RATIONALISATION

440. There are massive variations in NHP estimates based on widely different interpretations of KCM formula by stakeholders. For example, as per existing practice adopted by NEPRA, NHP for FY2020 would be Rs. 38.75 billion at Rs. 1.15 per kWh while using KP's version of KCM, the NHP figure works out to be more than Rs. 400 billion.

441. It is worth mentioning that for private hydro IPP, the rate for use of water resource as per the Power Policy 2015 approved by CCI is Rs. 0.425/kWh however, if the same resource (water) is used by the Federal Government for hydroelectric plant in the province, the rate shoots up to almost three times to Rs. 1.15/kWh. NEPRA has approved annual indexation of 5% on the current rate of Rs. 1.10 per kWh from FY 2016 which, if applied, would increase the rate to Rs. 1.273 per kWh for FY 2019-20.

442. The Committee did not however find any record which shows that the CCI has approved such indexation over the rate of PKR. 1.10/kWh. Regardless of nomenclature, essentially it is an issue of water pricing, for which, the formula generally used globally is based on unit of electricity produced.

443. Therefore, there is an urgent need to review the situation while learning from countries with significant hydro generation such as Brazil, China, Canada & India. In light of the economic strain it is causing, a consensus has to be developed between stakeholders on a revised and sustainable NHP formula which the consumers and the power sector economy can afford.

TRANSMISSION CONSTRAINTS

444. CPPA-G[57] has highlighted the transmission network congestion leading to despatch of expensive power plants which are lower down the merit order. Therefore, the Federal Government should facilitate the requisite investments in NTDC's and DISCOs' network to remove constraints.

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[57] Power Purchase Price Forecast (FY2019-20) by CPPA-G-G

66% PLANT FACTOR FOR RLNG BASED IPPS

445. The ring-fenced pricing mechanism of RLNG and relatively high price of LNG imported[58] under the term-contracts make the fuel more expensive than domestic natural gas. Further, due to a continued slump in international LNG market, the spot prices have dropped to lower than USD 3 per MMBTU[59] for March 2020 whereas, because of these legacy contracts, the consumers will be paying over USD 10 per MMBTU[60].

446. The preferred option would be price reduction as well as removal of the 66% plant factor requirement, which will yield substantial savings[61]. However, this will require renegotiating the terms of the LNG supply contract with Qatar. Reducing the minimum monthly LNG supply quantities by spreading them over a longer period will also help.

WEIGHTED AVERAGE COST OF GAS

447. While the supply of imported LNG, after regasification, is through the same gas distribution network of SNGP and SSGC which carries natural gas from domestic fields, the pricing of RLNG is ring-fenced i.e., it does not become part of cost of gas in the formula for determining selling prices for domestic gas.

448. The major gas producing provinces are averse to RLNG becoming part of the WACOG as they claim that it would be a violation of the Article 158 of the constitution, i.e.: "*The Province in which a well-head of natural gas is situated shall have precedence over other parts of Pakistan in meeting the requirements from that well-head, subject to the commitments and obligations as on the commencing day*".

449. It is clear that gas usage and pricing are two mutually exclusive subjects and perhaps the main reason for the Provincial opposition to combining the cost of RLNG and domestic gas is its potentially negative impact on Gas Development

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[58] Pakistan imports 800 MMCFD LNG under term contracts of which 600 MMCFD is priced at 13.37% of Brent.

[59] https://www.thenews.com.pk/print/611962-window-opens-for-pakistan-to-hit-a-low-cost-lng-jackpot

[60] https://psopk.com/en/product-and-services/product-prices/liquefied-natural-gas-lng

[61] https://www.thenews.com.pk/amp/549522-end-to-gas-deal-for-rlng-power-plants-pso-scuttles-power-division-s-move

Surcharge (**"GDS"**)[62]. As domestic gas is cheaper, combining it with more expensive RLNG could reduce the GDS accruing to the provinces. Nevertheless, declining domestic natural gas supplies and potential imports of cheaper LNG by the private sector would in any case constrain the provinces' future GDS revenues. The Government can offer an alternate mechanism offering minimum GDS revenues for provinces in return for their consent for making RLNG part of WACOG.

450. Inclusion of RLNG in WACOG would:

   i. Help in lowering the cost of electricity generation;

   ii. Enable more efficient natural gas consumption by moving the power plants with higher thermal efficiency up on the merit order.

   iii. Ease the accumulation of circular debt not only in the power sector but also the one that has started building up in the natural gas sector due to supply of RLNG to domestic consumers; and

   iv. Resolve the issue of inefficient gas based old GENCO's getting up higher in the merit order due to availability of cheaper gas.

REDUCING DISTRIBUTION INEFFICIENCIES

451. Reducing inefficiencies in the power distribution chain requires substantial improvement at two levels:

   i. Bringing down T&D losses; and

   ii. Improving billing recoveries.

452. Achieving meaningful gains in these two areas would require major revamping of DISCOs' governance structures and investment in infrastructure and human resources. Improvements are not possible without an element of deterrence for both the electricity service providers (DISCOs) and consumers to stop perpetuating the theft and other unlawful activities.

453. In this regard, amendments to the NEPRA Act in 2018 included a newly introduced section which empowers NEPRA to administer complaints of theft and over billing

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[62] GDS = Average Selling Price (local gas) – WACOG – Distribution Margin

whereby they can either impose a fine themselves on the entity or file a direct criminal complaint against an individual involved in the theft. This was a major procedural change aimed at simplifying the handling of cases of theft and overbilling:

> ***35A. Offices of complaints regarding over-billing etc.*** *(1) Notwithstanding anything contained in section 38 or section 39, the Authority may establish district level complaint offices to hear and decide complaints regarding overbilling, non-compliance of instructions respecting metering and collection of approved charges, disconnection in case of non-payment of charges, electric power theft and use of energy for purposes other than for which it was supplied.*
>
> *(2) The manner and procedure whereby consumers and licensees may make complaints under this section shall be specified*[63]*:*
>
> *Provided that the office of complaints shall, on receipt of a complaint, before taking any action thereon, give notice to the licensee or any other person against whom such complaint has been made to show cause and provide such licensee or such other person an opportunity of being heard.*
>
> *(3) If, on inspection by an office of complaints, a willful contravention against a licensee or any other person is established, a person and any such person that is party to the contravention shall be punishable in case of –*
>
> *(i) a licensee, with a fine under section 27B;*
>
> *(ii) an employee of a licensee who is found to be party to the contravention complained of,* ***to imprisonment for a term which may extend to three years or to a fine which may extend to ten million rupees or to both;***
>
> *(iii) a consumer that is a company, with a fine under section 27B; and*
>
> *(iv) any other individual who is found to be party to the contravention complained of, to* ***imprisonment for a term which may extend to three years or to a fine which may extend to ten million rupees or to both.***

454. NEPRA can start by setting up offices to deal with these issues in the high theft districts and issue the relevant procedural regulations in order to give effect to this provision.

455. Some DISCOs also suggested assistance of Rangers to control theft and recovery of arrears in areas with high losses and less recovery.

OPTIONS FOR BETTER MANAGEMENT OF DISCOS

456. The poor performance of distribution sector can be gauged from its billing recoveries and level of transmission and distribution losses. The following table

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[63] In terms of section 2 (xxva) "specified" means specified by regulations made under this Act, i.e. regulations are to be made by NEPRA to give effect to this provision.

illustrates how each DISCO contributed towards the loss to the sector, in descending order, which is reflected in the accumulation of circular debt during the last six years ending June 30, 2019.

Table 61 - Financial Impact of Losses and Under Recoveries

	Financial Impact (2014-2019)				
DISCOs	**T&D loss**	**Under Recoveries**	**Total**	**Disco-wise**	**Accumulated**
	PKR billion			**percentage**	
QESCO	28.55	204.79	233.34	30%	30%
PESCO	55.33	71.55	126.88	16%	46%
SEPCO	37.53	74.42	111.95	14%	60%
HESCO	30.02	60.93	90.95	12%	71%
IESCO	2.18	76.05	78.23	10%	81%
LESCO	39.50	27.01	66.51	8%	90%
MEPCO	18.28	14.51	32.79	4%	94%
TESCO	1.93	18.02	19.95	3%	96%
GEPCO	2.55	16.95	19.50	2%	99%
FESCO	5.75	2.51	8.26	1%	100%
TOTAL DISCOs	**221.62**	**566.74**	**788.36**	**100%**	

457. Three options are proposed below for improving the management of DISCOs:

PUBLIC-PRIVATE PARTNERSHIP

458. Efforts to reform DISCOs without change in ownership structure is unlikely to yield sustainable results. There is overwhelming evidence from power sector (e.g., K-Electric) as well as other sectors (banking, cement) that real turnaround takes place under private ownerships because the private sector can respond better to disruptive technological changes leading to paradigm changes in conventional public utility models.

459. A public-private partnership structure with private sector management control would be a preferred model here. The Sindh Engro Coal Mining Company and Kot Addu Power Plant are examples of successful public-private partnership. The Federal Government can consider offering 26-36% ownership in DISCOs with majority voting rights (by creating a new class of shares) to qualified private

investors. The shareholding offer can be by way of additional capital issue so that the proceeds stay in the DISCOs for investment.

PRIVATIZATION OF COMMERCIAL ACTIVITIES OF DISCOS

460. The amendments to the NEPRA Act in 2018 segregates the network management function from the supply function of the DISCOs[64]. The latter includes meter reading, billing, collection and customer services towards these activities. This supply function can be auctioned and handed over to the private sector while the Federal Government can continue to retain wire business only. Under this model, the non-risky business will remain with Government in shape of assets whereas the risky business requiring better management will be passed on to the private sector.

461. Since the DISCOs are deemed to be suppliers till April 2023, this would also be a good interim measure before transitioning to a completely independent supply segment in the power sector, driven by market driven supply and demand.

462. Turkey is a good example of this model where the wire business is with the government and commercial activities are passed on to retailers and bulk suppliers. The potential downside of this model is continued dependence on the government for infrastructure improvements, planning and decision-making.

BREAKING DOWN DISCOS

463. Along with the two options recommended above, the Federal Government should consider breaking down DISCOs into corporate units with a smaller and more manageable service territory. This would entail a de-merger of the ten DISCOs into such number of companies as are suited to the needs of their consumer base.

GOVERNANCE CHANGES AND BALANCE SHEET RESTRUCTURING

464. Governance changes and balance sheet restructuring of DISCOs are imperative whether or not ownership structure is changed. The DISCOs should have independent boards and qualified professional management, and direct involvement of the ministries in the affairs of the companies should be minimised.

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[64] Section 23E(1) of the NEPRA Act.

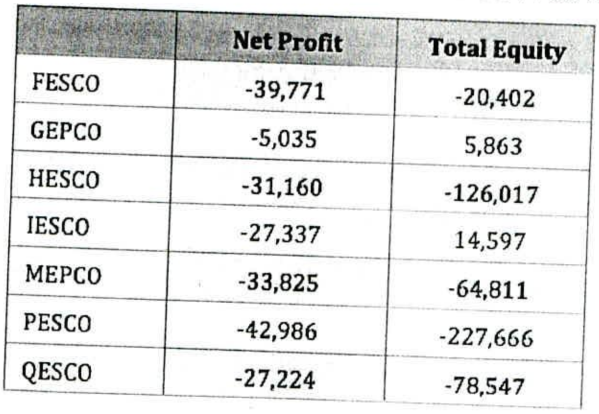
465. The government has pledged performance-based management of DISCOs, as part of energy sector policies[65] conveyed to the IMF, i.e.: '*To improve efficiencies and collections the government will sign performance-based contracts with all DISCOs by end-January 2020. The contracts will contain KPIs for improvements in collection, reductions in losses, and meeting the regulatory timelines for petitions submissions, with mechanisms to reward good performance and/or compensate for shortfalls. DISCOs will submit quarterly performance reports to NEPRA and will be published on NEPRA's website.*'

466. The operational independence of DISCOs is not possible without a strong financial position. As per the available annual accounts of seven DISCOs for FY2018, five of them had net negative equity balances.

467. Historically, DISCOs' tariff determinations and their notifications by the Federal Government were delayed on account of political and legal constraints. Consequently, the financial statements of the DISCOs were unreflective of their true and fair financial position. While their costs were reflected in the periods they were incurred, the revenues were distorted due to delays in determination and/or tariff notification.

468. Delayed tariff notifications result in large prior year adjustments in subsequent periods' tariffs and are then reflected in DISCOs' financial statements.

Table 62 - Equity Position of DISCOs FY2018



	Net Profit	Total Equity
FESCO	-39,771	-20,402
GEPCO	-5,035	5,863
HESCO	-31,160	-126,017
IESCO	-27,337	14,597
MEPCO	-33,825	-64,811
PESCO	-42,986	-227,666
QESCO	-27,224	-78,547

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[65] IMF Country Report 19/380, December 2019, pp 59.

469. A weak financial position impairs the DISCOs' ability to make the requisite investments for lowering T&D losses, reduce the number of overloaded feeders/transformers and undertake network expansion, all of which can help towards alleviating the circular debt problem. Further, a fragile financial position[66] makes it very difficult to privatise the DISCOs, especially the weaker ones.

470. Balance sheet restructuring of the DISCOs would require a combination of fresh capital injection, conversion of deferred credit into equity, etc.

CLOSING THE LOOPHOLES PERMITTING EXCESS BILLING

471. As noted earlier, a growing number and amount of running defaulters raises doubts about whether they represent disguised T&D losses (excess billing) or genuine billing. A 2004 WAPDA approval allowed HESCO to adjust excess billing without credit of units and the company apparently still continues to use it. There is a need for transparency in billing by closing any loopholes providing room for fictitious billing. Moreover, reputable chartered accountancy firms should be engaged to carry out detailed scrutiny of receivables from running and permanent defaulters to ascertain their recoverability.

472. Any non-recoverable amounts should be written-off and legal proceedings should be initiated for recovery of others in terms of section 35A of the NEPRA Act.

RESOLVING QESCO

473. The two main issues with QESCO are high technical losses and very low bill recovery rate. The technical loss, estimated at about 20% (out of total T&D loss of 23.6%), is primarily because of a vast geographical spread of the company's network supplying relatively small quantity of electricity. QESCO's units purchased to network ratio is about 44% lower than the average of all DISCOs.

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[66] Negative equity balances, large unfunded pension obligations and large receivables from running/disconnected defaulters

Table 63 – QESCO Units Purchased to Network Ratio Relative to All DISCOs

	Network Size (KM)			Units Purchased	Units/Network	T&D Loss
	HT	LT	Total	(GWh)	Size (KWh/KM)	
LESCO	29,309	15,001	44,310	24,338	549,277	13.2%
GEPCO	23,234	18,541	41,775	11,100	265,711	9.9%
IESCO	25,458	27,041	52,499	11,838	225,488	8.9%
FESCO	41,262	27,154	68,416	14,970	218,807	9.8%
PESCO	36,678	45,121	81,799	14,427	176,375	37.1%
MEPCO	76,057	49,992	126,049	19,367	153,644	15.8%
HESCO	28,305	15,005	43,311	5,557	128,300	29.5%
SEPCO	24,618	13,340	37,958	4,412	116,222	37.0%
QESCO	39,712	15,803	55,515	6,257	112,711	23.6%
TESCO	10,212	6,278	16,490	1,821	110,412	12.0%
TOTAL	**334,844**	**233,277**	**568,121**	**114,086**	**200,813**	**17.7%**

474. Moreover, about 3/4th of QESCO's electricity sales are to agriculture tube-wells, where collection of billing amount as well as subsidies from the Federal Government pose huge challenges. Technical solutions based around distributed generation and micro-grid systems should be undertaken on fast track basis to curtail technical losses.

475. This could be aimed especially in the area of agriculture tube well where solar power is promising to become a cheap and viable solution to meet the agriculture sector needs, off the traditional grid. A cost and benefit analysis could measure the benefit of providing cheap solar power at affordable terms and conditions. This could include concessional financing for the procurement of solar tube wells. Additionally, alternative solutions should be explored for meeting the water needs of the province's irrigation and drinking water to reduce the reliance on tube wells.

REGULATORY AND FISCAL INEFFICIENCIES

476. Three observations can be made about current consumer-end electricity tariffs:

a. The overall tariffs are high;

b. There are large tariff variations across[67] consumer categories; and

c. The incidence of taxation on electricity bills is heavy.

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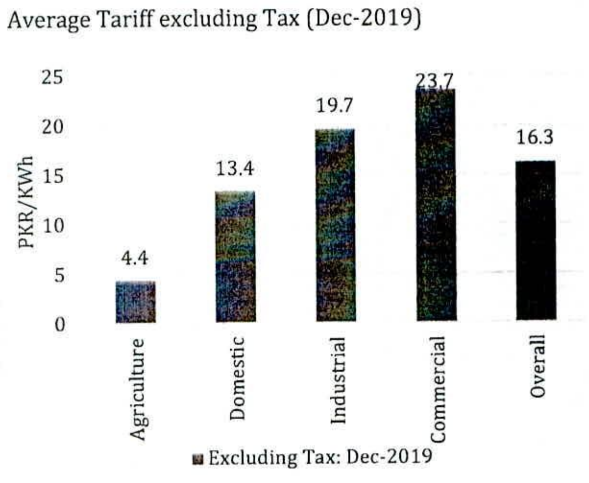
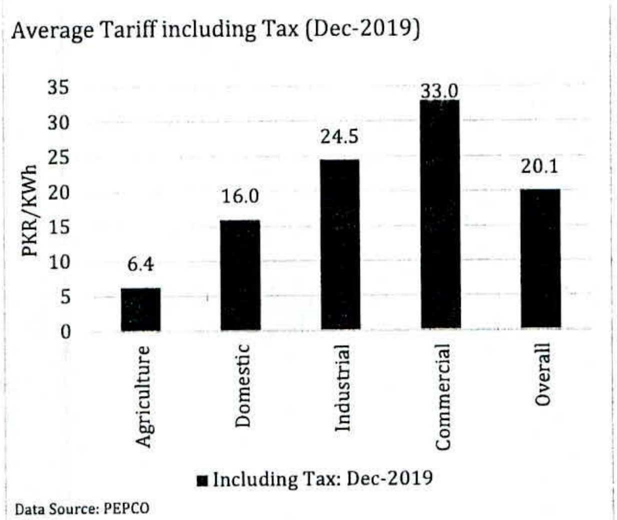
[67] And within the domestic category.


Average Tariff excluding Tax (Dec-2019)

Data Source: PEPCO


Average Tariff including Tax (Dec-2019)

Data Source: PEPCO

477. Large cross subsidies (especially in the domestic consumer category) and heavy tax incidence are contributing to grid defection by the industrial sector and solarisation by commercial and high-end domestic consumers. There is therefore a need for rationalisation of consumer end tariffs to raise demand for grid electricity.

Table 64 - Electricity Tariff for Domestic Sector (PKR/KWh)

Consumption Slabs	NEPRA Determined	Notified Tariff	Tariff Subsidy
Up to 50 Units	4.0	2.0	2.0
Up to 100 Units	13.9	5.8	8.1
101-200 Units	15.9	8.1	7.8
201-300 Units	16.8	10.2	6.6
301-700 Units	20.0	19.0	0.9
Above 700 Units	22.4	22.1	0.2
TOU - Peak	20.8	22.1	-1.4
TOU - Off Peak	14.2	15.8	-1.6

478. Further, the following contributes significantly to the build-up of circular debt:

a. Inflexible tariff methodologies;

b. Delays in tariff determinations and notifications due to legal challenges and political considerations;

c. Under-budgeting of tariff subsidies and their slow disbursements; and

d. Tax anomalies.

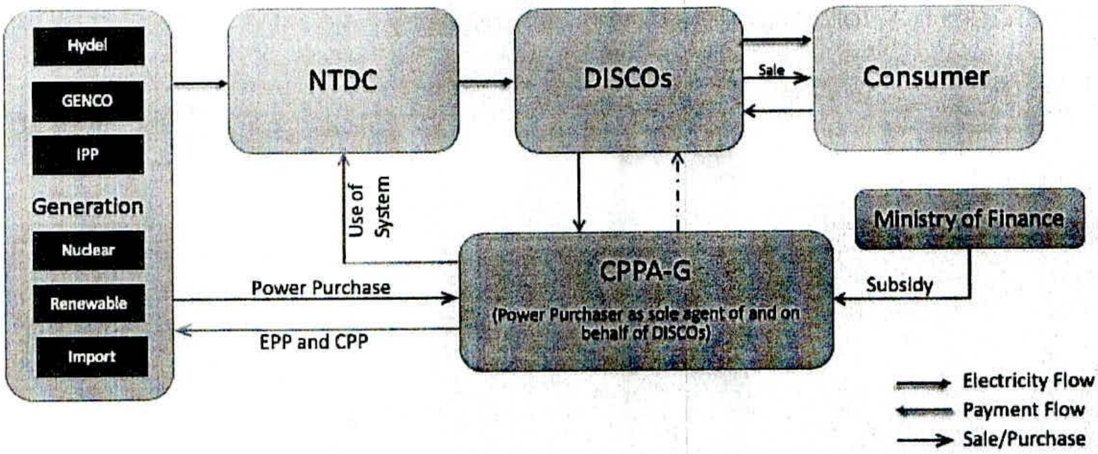
479. Each of these can be addressed by streamlining processes and procedures of tariff determination, implementation and recovery. It is pertinent to mention that NEPRA and the Federal Government have been seen to remain at loggerheads on these issues, whereas, in order to resolve these NEPRA and the Federal Government need to work together to help transition the sector to competitive markets.

480. In this regard, the NEPRA Act requires NEPRA's input into the National Electricity Policy and National Electricity Plan under section 14A, and conversely, NEPRA is to consider the Policy and the Plan in its regulatory objectives.

SECTION 3 - FUTURE ROADMAP - COMPETITIVE POWER MARKETS

THE CURRENT STRUCTURE

481. Pakistan's power market is currently structured as a 'Single Buyer Model' as shown in the following diagram:



The International Experience in Single Buyer Markets

482. In December 2000, World Bank (Note Number 225) termed the single-buyer model as a ***"Dangerous Path"*** and highlighted its major disadvantages[68]:

- Decisions about adding generation into the system is made by bureaucrats who may find it difficult to resist state guaranteed expansion plans lobbied for by powerful interest groups;
- The guarantees given by the State in a single buyer model can undermine the government's creditworthiness and macroeconomic stability;
- When demand falls short of projections, electricity prices rise on account of take-or-pay provisions and it is difficult to pass these onto consumers, thereby burdening taxpayers;

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[68] Lovei, "The Single-Buyer Model : A Dangerous Path toward Competitive Electricity Markets" (http://siteresources.worldbank.org/EXTFINANCIALSECTOR/Resources/282884-1303327122200/225Lovei-1211.pdf).

- Since a single buyer system is usually state-owned/dominated, it is not driven by profit motives and instead finds it difficult to take tough decisions against inefficiencies because of socio-political pressures. As a result, there is little or no incentive for distribution companies to increase collection;
- The government's control over dispatch of electricity in a single buyer model allows ample space for corruption where lobbies in the generation segment find it easier to offer bribes in exchange for preferred treatment; and
- There is a higher pressure from lobbies in a single buyer model to delay the transition by government into a competitive electricity market model.

483. ***As also highlighted in other parts of this report, unfortunately, Pakistan has suffered from each of these disadvantages.***

Single Buyer Market in the Context of Pakistan

484. In Pakistan, a failure to transition out of a single buyer market dominated by the Federal Government has played a key role in some of the major problems plaguing the power sector. These are explained in the following paragraphs.

PAYMENT BURDEN ON SINGLE BUYER

485. Since the Federal Government, through its wholly owned companies, is a single buyer the entire financial risk of the sector is being borne by the Federal Government. The likelihood of default on payment obligations towards electricity generators is therefore also higher in the current model and the magnitude of such a possibility can severely strain the economy of Pakistan.

486. In a competitive market on the other hand, the transactions are structured in a way that the payment obligations are spread out over multiple buyers and sellers. A structured market itself contains checks and balances, such as the settlement guarantee fund in neighboring India[69] as well as in the US and various European countries. This supports the systemic integrity of the market in case of major defaults or liquidity constraints.

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[69] https://www.iexindia.com/Uploads/LegalDocument/03_12_2018IEX%20Rules.pdf

HIGH COST OF ELECTRICITY

487. Regionally, Pakistan has the highest cost of electricity in all three major consumer categories:

Table 65 - Regional Comparison of Cost of Electricity[70]

	Cents/kwh	Residential	Commercial	Industrial
1	Pakistan	1.3 – 15.4	12.4 – 15.9	11.8 – 12.5
2	India	4.2 – 11.2	8.4 – 11.9	10.9
3	Bangladesh	4.1 – 12.6	10.8	6.8

488. Access to cheap and reliable power is vital to the socio-economic development of a country. While we have had reactive power policies, which have focused mostly on adequacy of generation, hardly any consideration has been given to the medium to long term financial or social impacts of the policies. Further, once a policy was issued, it was hardly ever revised to the interest of the consumers. Therefore, cost implications, fuel mix, payment capacity of consumers, infrastructure expansion and business models of DISCOs were hardly considerations in the development of the electricity markets of Pakistan.

489. This has had a cyclical impact – policies designed only to incentivize generation by offering long term guaranteed returns ended up reinforcing the single buyer model because with guaranteed returns, competition was not an option. The resulting lack of competition in turn allows leverage to current players in the generation segment of the power markets, who prefer status quo to transitioning out of the current structure.

490. Consequently, because in a single buyer model the focus of the government is largely on balancing supply of power against demand, Pakistan's tariff cost and efficiency of service has remained a largely unresolved matter against the context of cyclical periods of excess demand and excess supply.

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[70] Pakistan - Applicable Consumer Tariff for XW-DISCOs in Pakistan; India - https://www.tatapower-ddl.com/Editor UploadedDocuments/Content/Tariff ad English 16x38- 2019.pdf; Bangladesh - https://dpdc.org.bd/article/view/52/Tariff&; Exchange rates: Bloomberg (February 12, 2020)

491. In a competitive power market on the other hand, cost reductions, improved efficiencies, payment capacity of consumers etc. of themselves drive the demand and supply of electricity, allowing for a financially more viable power sector overall.

492. For example, currently, approximately 40% of Pakistan's generation mix depends on imported fuel-based power plants (RLNG, imported coal, etc.). The average variable cost of generating power from these fuels is much higher compared to hydro, renewables and indigenous coal reserves and also burdens the country in the form of balance of payment crisis. In a competitive market, in order to be able to sell the electricity being generated, the cost of production will have to be lowered by the generation company, therefore building in an incentive into the system to either move to cheaper fuel sources or use imported fuels more efficiently.

LACK OF COMPETITION

493. The lack of competition in the generation and distribution/retail segments has created problems in the entire supply chain of electricity. On the generation side, it has led to the development of tariff regimes (either cost plus or upfront tariff regimes) which are more investor centric than consumer oriented. The result is excess profitability by generation companies on account of lack of regulatory oversight and faulty pricing models. On the distribution side, the lack of competition translates into inefficient service delivery whereby DISCOs are burdening consumers with high losses, under recoveries and theft.

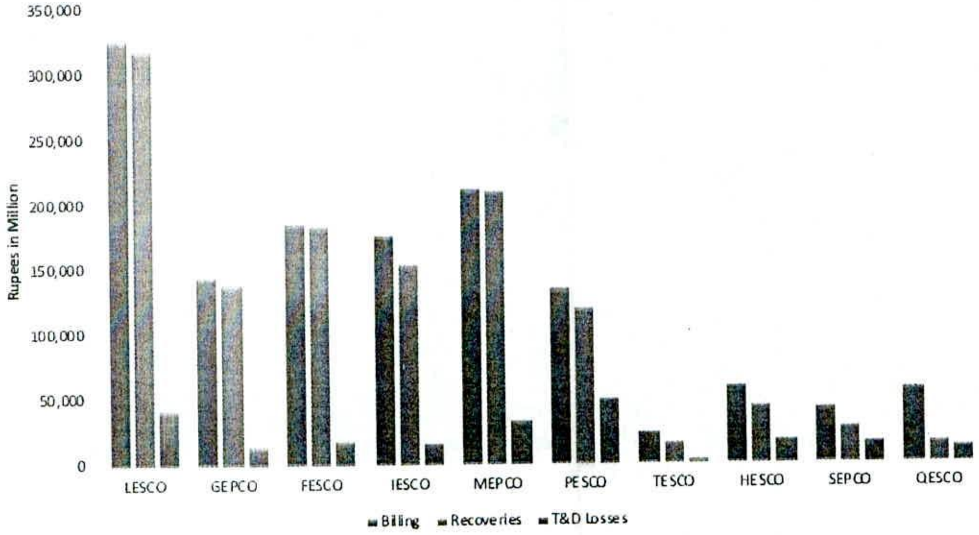
494. On the other hand, in a competitive market, because the eventual sale of electricity to consumers, i.e. the electricity supply function, is established and regulated independently of the distribution function. There are usually more than one electricity suppliers in a competitive market, hence actual recoveries are improved on account the competition to enhance the consumer base by reducing the cost of electricity in order to maximize their profits. The cyclical build-up of tariff on account of revenue shortfall of DISCOs is therefore curtailed in a competitive market structure.

LOW RECOVERIES & HIGH LOSSES IN A REVENUE BASED DISTRIBUTION MODEL

495. The current business model for DISCOs is revenue capped by NEPRA, and any differential in revenue on account of variables inter-alia, low recoveries, high losses, low demand, etc. is neither penalized nor incentivized, therefore minimizing the room for efficiency gains and ultimately causing high electricity tariffs. Such models are generally unsustainable in the scenario of low electric load growth and high distributed energy penetration which is prevalent in Pakistan.

496. The DISCOs' revenue declines when demand for electricity drops, however, its costs remain unchanged, ultimately overburdening the end consumers. It is therefore necessary to shift to a profit-oriented business model aimed at enhancing profits by increasing the consumer base, reducing technical and administrative losses, ensuring recoveries and increasing reliability of their services.

497. Further, a component of the consumer end tariffs is the Aggregate Technical & Commercial losses allowed by NEPRA in determining the revenue requirements of a DISCO. The actual losses incurred are however much higher than the allowed losses, and the difference between the two ends up translating into inadequate recovery of the revenue requirement of distribution companies. A summary of non-recoveries and T&D losses by DISCOs is depicted below:



Distribution Companies
Billing, Recovery and T&D Losses
2019

498. This shortfall in revenue requirement of DISCOs translates into a higher tariff request from NEPRA by the DISCO in subsequent years.

SUPPRESSION OF DEMAND

499. Demand forecasting is a key variable in the entire power supply chain and is vital to planning supply additions which usually take a long lead time. In the past, our demand forecasting function had been weak and didn't capture ground realties like technology advancements, conservation measures, etc. This led to over estimation of electricity demand resulting in mismatch between GoP policies and actual country needs causing an induction of surplus installed capacity.

500. The demand forecasting function tends to be much more evolved in competitive power markets on account of the financial implications to various participants in the power market.

NON-COMPLIANCE OF COST OF SERVICE-BASED TARIFFS

501. Cost of service-based tariff is the true cost of supplying electricity to a certain class of consumers In Pakistan. Non-compliance of cost of service-based tariffs has led to inefficiencies and disturbed the economic viability of the sector. This leads to the discriminatory treatment among various classes of consumers. A tariff structure in which true costs are not passed on to consumers causes inefficiencies and misguides investment decisions in the overall supply chain of electricity.

502. Because of socio-political pressures, it is usually very difficult for a government to eliminate this consumer class discrimination, so it ends up subsiding the cost of electricity as the cost of not subsidizing is too high to sustain politically. This places a large burden on the exchequer.

503. In competitive markets, the State is largely unburdened with bearing the cost differential between regulated end-consumer tariff and affordable end-consumer tariff, since its role becomes limited to providing an enabling environment in which the power sector players can operate efficiently and profitably while minimizing market abuse by the participants.

Overcoming the Single Buyer Crisis

504. In order to permanently address most of the financial and technical issues of Pakistan's power sector, a structural and regulatory reform is required. Such reform has been attempted since the mid-90's with the unbundling of WAPDA, establishment of NEPRA, creation of DISCOs, and most recently, the separation of CPPA-G from NTDC.

505. This last reform was originally proposed as part of a program aimed at enabling the ten DISCOs, instead of NTDC, to start purchasing electricity, i.e. a multi-buyer market. However, subsequently, the Federal Government tasked CPPA-G as the sole purchase agent of all DISCOs.

506. The historical record shows an unwillingness of the Federal Government entities to reduce their footprint in the sector, which has repeatedly led to a breakdown of reform efforts. This reluctance could be because of a number of reasons, including fear of job loss, an inherent mistrust between the State and private investors, concerns about loss of control over assets which provide socio-political leverage to the State, etc. In any case, our experience, as well as international precedents, demonstrate a political disincentive for the State to be efficient, which results in medium and long-term sectoral dysfunctions (financial and structural).

507. This could be a reason why the Federal Government has been largely unsuccessful in driving down the cost of electricity, as well as why the Federal Government resisted the transition to competitive markets.

508. This transition is, however urgently required, and the role of the State in the power sector has to be limited to policy, planning and broader regulation. If we are to permanently address our power sector issues, the Federal Government, the Provincial Governments, and NEPRA will have to engage private sector investment and create a competitive environment among different players to enable them to become the drivers of efficiency and lowered electricity costs.

THE MOVE TO COMPETITIVE ELECTRICITY MARKETS

509. In April 2018, the Parliament introduced major reforms in the NEPRA Act, with a view to providing the regulatory framework within which NEPRA and the Federal Government could work towards establishment of a multi-buyer competitive electricity market. The intent of the Parliament was demonstrated through the amendment to the preamble of the Act which now reads:

> *"AND WHEREAS it is expedient to ensure the elimination of energy poverty in the country, to ensure the highest standards of transparent, certain and effective regulation of the electric power markets of Pakistan, to provide the legal framework within which a competitive electric power market can develop and sustain, to make special provisions for the development of renewable electricity markets in accordance with the international commitments of Pakistan as well as the responsibility of Pakistan to support and encourage measures to effectively mitigate adverse climate change and to effectively manage conflict of interest of the State in relation to development of the electric power markets of Pakistan"*

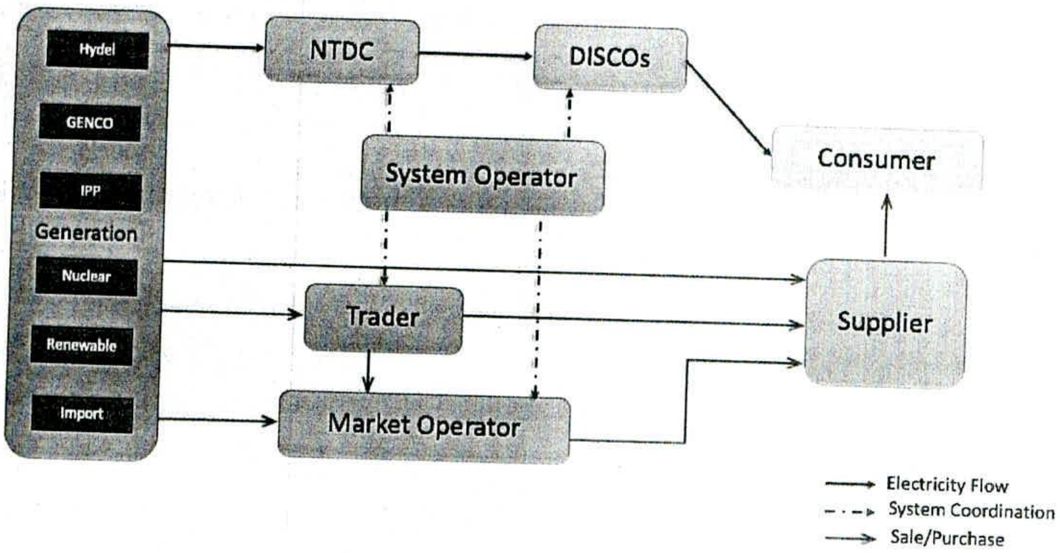
510. A summary of the market related amendments is tabulated below:

Impact	Responsibility
De-License Generation	
Generation companies will continue to comply with minimum technical and safety standards but will establish a plant on their own risk. Eventually generation tariffs by NEPRA will be replaced with market driven tariffs, subject to checks against overpricing by NEPRA. Generation companies can sell to other licensees, e.g. transmission companies, market traders, distribution companies etc., however they cannot sell to the end consumer without obtaining a supply license (explained below).	**Section 14(B)(5)** - Federal Government to notify plan for de-licensing by April 2023
Set up Independent System Operator ("SO")	
A SO oversees the economical and continuous transportation of electricity from generation till consumption, in accordance with the NEPRA approved grid code. An independent SO will also be able to independently identify and flag system constraints at the transmission and distribution level. Section 1(3) of the Act makes this provision effective in April 2023, but Federal Government can notify an earlier date for this as well.	**Section 23G** - Federal Government, either on its own or on the recommendation of NEPRA, to make rules for grant of system operator license, including minimum solvency and technical and human resource requirements. **Section 50(2)** - NEPRA to update and convert relevant standards and procedural requirements from rules to regulations.

Segregation of Distribution and Retail Function (Supply)	
A distribution company in Pakistan undertakes two functions: Non-risky: Management of distribution network; and Risky: Retail of electricity to consumers (supply function). The Act requires two separate licenses for each function. The supply license is non-exclusive, i.e. multiple suppliers possible in one territory for greater competition leading to higher efficiency. Supplier can purchase electricity directly from a generation company, through an electricity trader or from a platform, enabling them to offer different packages to consumers, which in turn will be an incentive for generation companies to produce cheaper electricity. Distribution companies are deemed to be suppliers till April 2023, i.e. DISCO's can in the first instance outsource their retail business operations for improved efficiencies. The supply license provisions became effective immediately with amendment, i.e. supply functions can commence as soon as the legal framework is put in place by the Federal Government and NEPRA. Opening the supply market will leave only the non-risky aspect of distribution with the Government and in that sense is an alternative to privatization.	**Section 23E -** Federal Government, either on its own motion or on the recommendation of NEPRA, to make rules laying down eligibility criteria for grant of electricity supply license, including minimum solvency and technical and human resource requirements. **Section 50(2) -** NEPRA to update and convert relevant standards and procedural requirements from rules to regulations.
Electric Power Trader	
The law envisages the existence of multiple electric power traders in the market who will act as intermediaries in bilateral contracts between sellers of electricity and electricity suppliers. Traders license is a non-exclusive license thereby allowing competition in the sector. The balance between electricity produced and electricity consumed will be undertaken by the electric power trader in coordination with the balancing mechanism given by the system operator. The traders license regime has been made operational immediately upon the coming into effect of the amendment to the Act, i.e. April 2018.	**Section 23C -** Federal Government, either on its own motion or on the recommendation of NEPRA, to make rules laying down eligibility criteria for grant of electric power trader license, including minimum solvency and technical and human resource requirements. **Section 50(2) -** NEPRA to update and convert relevant standards and procedural requirements from rules to regulations.
Market Operator ("MO")	
In terms of the NEPRA Act, MO is "... *a person responsible for the organization and administration of trade in electricity and payment settlements among generators, licensees and consumers*". MO is essentially a platform providing a market for electricity trading and consequent payment settlements. MO admits market participants (generators, traders, suppliers) and is independent of these participants so that: The market is operated in a fair and transparent manner;	**Section 23A -** Federal Government, either on its own motion or on the recommendation of NEPRA, to make rules laying down eligibility criteria for grant of market operator license, including minimum solvency

The market is able to withstand lobby pressures; and The market can independently focus on competition which brings efficiency and help provision of least cost electricity to consumers. MO transacts business under a regulated code, therefore providing certainty for investors and consumers alike. Section 1(3) of the Act makes this provision effective in April 2023, but Federal Government can notify an earlier date for this as well.	and technical and human resource requirements. **Section 50(2)** - NEPRA to update and convert relevant standards and procedural requirements from rules to regulations.

511. The following diagram broadly sums up the impact of the new market structure under the Act:



512. Under the new model, the physical infrastructure of NTDC, as a natural monopoly, can continue to be owned by the Federal Government. Insofar as the DISCOs are concerned, the law segregates their functions as follows:

i. Distribution: Ownership, operation, management or control of distribution facilities for the movement or delivery to consumers (section 2(v) of the NEPRA Act)

ii. Supply: Metering, billing and collection of the approved charges and disconnection in case of non- payment of charges, electric power theft and use of energy for purposes other than for which it was supplied and procedures for re-connection and recovery of arrears and other charges. (section 23F(2) of the NEPRA Act)

513. It is important to note that after April 2023, the existing DISCOs will not be able to undertake supply functions, unless a separate corporate entity is established and licensed.[71] This will automatically segregate the balance sheet of the DISCOs into risky (supply) and non-risky (distribution) activities. The result is that the risk of the Federal Government on the balance sheets of the DISCOs is minimized in the distribution function.

514. Further, the law allows multiple suppliers in a service territory in order to encourage market driven efficiencies, therefore the risk in the retail/supply is spread across multiple entities.

515. Even for the service territories where there are non-paying consumers, the balance sheet of the DISCOs will be strengthened by the segregation of the supply function, and their financial ability to improve network would be enhanced. However, in these areas the Federal Government may initially continue to take risk in the supply function till such time that the supply market is fully developed there. For this purpose, the Federal Government will have to propose incentives and support for the development of a supply segment in difficult service areas, including continued subsides to certain consumer classes, strengthening network availability, etc.

516. Following through on the legislatively mandated plan would therefore reduce the financial, social and political risks which the Federal Government has been bearing under the existing power policies and would also promote much needed efficiency and liquidity in the power sector. The law itself provides a mechanism ensuring this, as explained in the following paragraphs.

Implementation of the Reform

POLICY AND PLANNING

517. The newly enacted section 14A of the Act introduces a methodology to give effect not only to the market provisions but also on how to steer the overall sector finances

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[71] The law requires different conditions of licenses for distribution (section 20) and supply (section 23E), including minimum capital requirements and HR capacity.

and physical infrastructure in a structured, implementable and accountable manner.

> *"**14A. National electricity policy and plan.** – (1) The Federal Government shall, from time to time, with the approval of the Council of Common Interests, prepare and prescribe a **national electricity policy** for **development of the power markets**:*
>
> *Provided that in the development of policies under this section, the Federal Government may seek such input and assistance from the Authority as may be required.*
>
> *(2) The policies referred to in sub-section (1) shall provide for, inter alia–*
>
> *(a) development of systems based on optimal utilization of resources such as coal, natural gas, nuclear substances or materials, hydro and renewable sources of energy;*
>
> *(b) development of efficient and liquid power market design;*
>
> *(c) integration of national and provincial transmission systems;*
>
> *(d) special provisions for ensuring the development of a sustainable renewable energy market with a dedicated and gradually increasing share in the electricity power sector; and*
>
> *(e) any other matter pertaining to the development, reform, improvement and sustainability of the power sector.*
>
> *(3) The Federal Government may either on its own motion or the recommendation of a Provincial Government and, subject to the approval of the Council of Common Interests, review or revise the policies referred to in sub- section (1).*
>
> *(4) The Federal Government, in consultation with the Provincial Governments, shall prepare a **national electricity plan** in accordance with the policies prepared and prescribed under sub-section (1) and notify such plan once in five years:*
>
> *Provided that the Federal Government, while preparing or amending the national electricity plan, shall publish the draft national electricity plan and invite suggestions and objections thereon within thirty days of the notification:*
>
> *Provided further that a Provincial Government may, if required, propose an amendment to the national electricity plan, which may be adopted with the concurrence of the Provincial Governments and the Federal Government.*
>
> *(5) The Authority shall perform its functions in accordance with the national electricity policy and the national electricity plan."*

518. The salient features of section 14A are as follows:

- Broader electricity policy to be approved by the CCI to provide for:
    - Development of efficient and liquid power market design;
    - Integration of national and provincial transmission systems;
    - Reform, improvement and sustainability of the power sector.
- Five-year plan to be developed by Federal and Provincial Governments in order to give effect to broader policy objectives.

- NEPRA to provide support and input in the development of the Policy and Plan and to tie in its regulatory objectives and strategy with the approved Policy and Plan.

Impediments to the Transition to Competitive Markets

519. Key impediments to the transition to competitive markets include:

   i. Signing of long term PPAs by the Federal Government (through PPIB/AEDB/CPPA) offering lucrative incentives, which encourage the status quo instead of competition. In this regard, Section 1 already covers recommendations to move to a TaP contract methodology;

   ii. Tariff structures which have sustained sector inefficiencies and non-transparency. The existing tariff structure does not differentiate between price charged for energy, capacity, transmission, distribution and amount of cross-subsidies involved.

   iii. Lack of communication and coordination between the Federal and the Provincial Governments because of which a National Electricity Policy and National Electricity Plan under section 14A of the NEPRA Act have not yet been approved.

   iv. Lack of harmony between the rules and regulations of NEPRA with the newly amended NEPRA Act. NEPRA was to bring the rules and regulations made before 2018 in line with the amendments, which has not yet been done. The legal framework for licensing of system operator, traders, suppliers, market operator, and de-licensing of generation companies is therefore not yet in place.

   v. A good step forward is the Competitive Trading and Bilateral Contract Market Model (**"CTBCM Model"**) prepared by CPPA-G which has been approved by NEPRA in December 2019. In order to ensure a smooth transition to a multi-buyer market, the following aspects require further deliberations:

      - The CTBCM model has been prepared under rules which were made prior to the passage of the Act. The proposed plan in this model therefore now needs to be endorsed in terms of section 14A of the NEPRA Act, i.e. by the CCI at the policy level and the Federal Cabinet at the planning level.

- The CTBCM model introduces a new concept of Independent Auction Agents (**"IAA"**) to undertake bilateral contracts under section 25A of the NEPRA Act. However, section 25A applies only to activities which do not fall under one of the licensed activities[72]. In this regard, it is pertinent to mention that section 23D(2)(b) envisages bilateral contracts to be undertaken by a licensed trader, and therefore bilateral contracting is not possible except within the purview of section 23D.
- The CTBCM model proposes that PPIB and AEDB, which are both statutory bodies, should undertake the auction function as IAAs as registered persons under the NEPRA Act. However, section 24 of the NEPRA Act states that:

> ***"24. Licensees to be companies.*** *— Except the WAPDA, the PEDO or any other person specially exempted by the Authority, a license* ***or registration shall not be granted to any person unless it is a company registered under the Companies Ordinance, 1984*** *(XLVII of 1984)"*

WAY FORWARD – ESSENTIAL ACTIONS

520. In order to truly transition to competitive electricity markets, holistic efforts are required from all stakeholders to implement policy, legal, regulatory, institutional, technical, commercial and financial management related actions.

521. CPPA-G has prepared a roadmap for implementation in the next two years to operationalize the market. The same needs to be discussed by all power sector institutions with a view to reach an agreement on the plan of actions required for competitive power market set-up in the country in light of the applicable legislative framework.

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[72] Section 25A- Registration.- Any person providing electric power services, **other than generation under Chapter IIA or an electric power service requiring a license under this Act**, shall be registered with the Authority in the manner and subject to such conditions as may be prescribed.

522. Accordingly, it is proposed that:

i. A full-time committee comprising representatives of the Federal Government, the Provincial Governments and NEPRA should be established by the Cabinet in accordance with section 14A, to:

  - Develop a draft National Electricity Policy; and
  - Develop the draft five-yearly National Electricity Plans

  Such committee should be equipped with financial expertise as well as technical expertise. If the committee itself is not equipped they may be granted budgetary support to obtain support from local and international experts. This is important since the requisite skill set to propose and implement a plan for the transition to a competitive power market does not currently exist in the sector.

ii. Power Division should be restructured to function as a **Technical Ministry** of the Federal Government, staffed with experts in finance, energy economics and law who can perform various functions critical for moving towards competitive markets. Some of these are to:

  a. Undertake the functions of PPIB and AEDB with respect to existing PPA's;
  b. Coordinate with NEPRA for input in policy and plan as well as development of rules pertaining to the power sector;
  c. Coordinate with multilaterals; and
  d. Monitor the implementation of the Policy and Plan on behalf of the Federal Government and coordinate with the Provincial Governments thereon.

iii. The first proviso of section 50(1) of the Act mandates that:

> "*...pursuant to the coming into effect of the Regulation of Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2017,* ***the rules and regulations issued under this Act shall be brought into conformity with the amended provisions of this Act, where so ever required, within a period of one year from the date of coming into effect*** *of the Regulation of*

Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2017. "

It is therefore proposed that NEPRA may initiate this exercise at the earliest in order to ensure that the requisite regulatory framework is in place for the operations of competitive power market.

Note: Member, CPPA-G in the Committee was not in agreement with the concept of Competitive Markets discussed in this section, in particular with the following paragraphs:

- **510;**
- **512 to 515;**
- **519 (iii) and 519 (v); and**
- **522**

SECTION 4 – IMPLEMENTATION PLAN

523. The purpose of this section is to consolidate recommendations in Sections 1, 2 and 3 of this Report, and propose an action plan to the Federal Government for ensuring effective execution of the recommendations. Specific action points are outlined with the relevant entity which should be assigned responsibility. Overall responsibility to monitor progress of this plan should be with the Power Division, being the authorized arm of the Federal Government. This will require strengthening of the Power Division in the manner proposed below.

REVIEW OF PRIVATE POWER PRODUCERS

Recommendations	Timeline (Months)	Mechanism	Responsibility
Shift from USD to PKR based tariff for all IPPs	3	Change in Policy	Power Division
End Take or Pay arrangements	3	Change in Policy	Power Division
Establishment of Commission for Forensic Evaluation (forensic and legal audit of all IPPs)	1	Cabinet Approval under Pakistan Commissions of Inquiry Act, 2017	Power Division
Review set up costs of IPPs and Lahore Matiari HVDC Transmission	6	Commissions of Inquiry Act, 2017	Commission of Forensic Evaluation
Review risks highlighted in the Report	6	Commissions of Inquiry Act, 2017	Commission of Forensic Evaluation
Recover excess profits made from fuel, O&M, excess setup cost, etc.	3	NEPRA Act	NEPRA
Rectify IRR and debt payment frequency mismatch	3	NEPRA Act	NEPRA
Review IDC and other setup costs of coal IPPs to recalculate RoE	1	NEPRA Act	NEPRA
Review plant capacity benchmarks in renewable IPPs for a more prudent tariff sharing method and recover excess payments made	3	NEPRA Act	NEPRA
Introduce reasonable claw back mechanism in all tariffs (where required)	3	NEPRA Act	NEPRA
Verify fuel inventories of thermal IPPs and adjust outstanding payments against actual levels	Ongoing	Power Purchase Agreement	CPPA-G
Recover excess profits made by generation beyond capacity benchmarks from renewable IPPS	3	NEPRA Act	NEPRA
Consider retirement of GENCOs as well as IPPs established under the 1994 and 2002 Policy	3	Cabinet Approval on recommendations of Committee comprising Power Division, NEPRA and Ministry of Law	Power Division

CIRCULAR DEBT AND DISTRIBUTION INEFFICIENCIES

Recommendations	Timeline (Months)	Mechanism	Responsibility
Circular debt stock reduction/elimination and reduction of finance cost in line with Committee's recommendations	6	Cabinet approval of measures for one-time reduction with eventual payback from measures implemented by Power Division	Power Division/Finance Division
Debt reprofiling of public sector power plants [WAPDA, PAEC, GENCOs, 4 x 1200 MW RLNG based plants], renewable, CPEC and coal-based projects	3	Negotiate extension of project debt repayment period to 25 years	Power Division
Reduce finance cost on long term project debts, working capital and LPS	3	NEPRA through tariff review	NEPRA
Moratorium on new plants, delay and reconsideration of upcoming plants and non-renewal of plants reaching expiry	1	Cabinet direction to NEPRA, PPIB, AEDB and CPPA-G	Power Division
Novation of PPAs to KE instead of KE setting up new 900 MW RLNG and 700 MW coal-based projects	6	Conducting requisite technical studies for identifying solutions aimed at a) integration of KE and NTDC Systems, b) augmenting supply to KE and c) novation of PPAs of IPPs (coal, nuclear, wind) located in the south.	Power Division/KE
KE to submit timeline for retiring/mothballing old 1200 MW Bin Qasim plant			
Integration of NTDC and KE Systems			
Rollout of a comprehensive plan for electrification of domestic energy use for cooking, space heating, water heating and electronic vehicles for use in public transport	6	Preparation and execution of plans and policies	NEECA/Planning Division
RLNG contract renegotiation and inclusion in WACOG	3	Cabinet approval for re-negotiation and SC opinion on interpretation of Article 158 of the Constitution of Pakistan, 1973	Petroleum Division
Rationalization of natural gas tariff for captive power plants to incentivize their shift to the public grid and for GENCOs to be appropriately utilized in merit order	1	Cabinet Approval	Petroleum Division
Strengthen management of DISCOs, PEPCO, NTDC and PHPL	3	Cabinet Approval	Power Division
Restructure balance sheet of DISCOs	6	Conversion of deferred credit into equity	Power Division
Public private partnership/separation of wire and commercial business and possible breakup of DISCOs into smaller service territories	6	Identification of possible PPP collaborations/initiation of requisite legal actions under NEPRA Act	PPP Authority/Privatisation Commission
Payment of outstanding subsidies and devising a mechanism for sharing of future subsidies with provinces with at source deductions from amounts transferred under NFC	6	CCI approval on the recommendations of committee comprising Power Division, Finance Division and Law Division	Finance Division
Subcontracting recovery of receivables to private sector	3	NEPRA Act - Supply provisions	Power Division/NEPRA
Reform QESCO through distributed generation and micro grids	12	Conduct feasibility studies for distributed generation and micro grids (based on indigenous natural gas and renewables)	Power Division
Solutions for QESCO for water supply for irrigation and household consumption	12	Conduct feasibility studies for finding optimal solutions for meeting Balochistan's water needs	Ministry of Water
Rationalization of existing NHP	3	Cabinet approval	Power Division

FUTURE ROADMAP – COMPETITIVE POWER MARKETS

Recommendation	Timeline (Months)	Mechanism	Responsibility
Establish an inter-provincial committee to finalize draft Policy for approval of CCI and draft 5-year plan for approval of Federal Government	Immediate and ongoing	Section 14A NEPRA Act	Cabinet
Review CTBCM model to ensure it is in line with NEPRA Act	3 months	NEPRA Act - Market provisions	NEPRA
Develop rules to give effect to new provisions of the NEPRA Act regarding power markets: 1. Separate System Operator and Grid 2. Separate Distribution and Supply 3. Establish Electricity Traders	6 months	NEPRA Act	NEPRA/Power Division
Develop regulations to give effect to new provisions of the NEPRA Act and bring old rules in line with amended NEPRA Act	6 months	NEPRA Act	NEPRA

OVERSIGHT OF ACTION PLAN

524. The implementation of this plan will require continuous coordination and monitoring to keep pace with local and international developments in the power sector. It is essential to pass on the responsibility for overall supervision to one entity, which can ensure effective and timely execution of all recommendations.

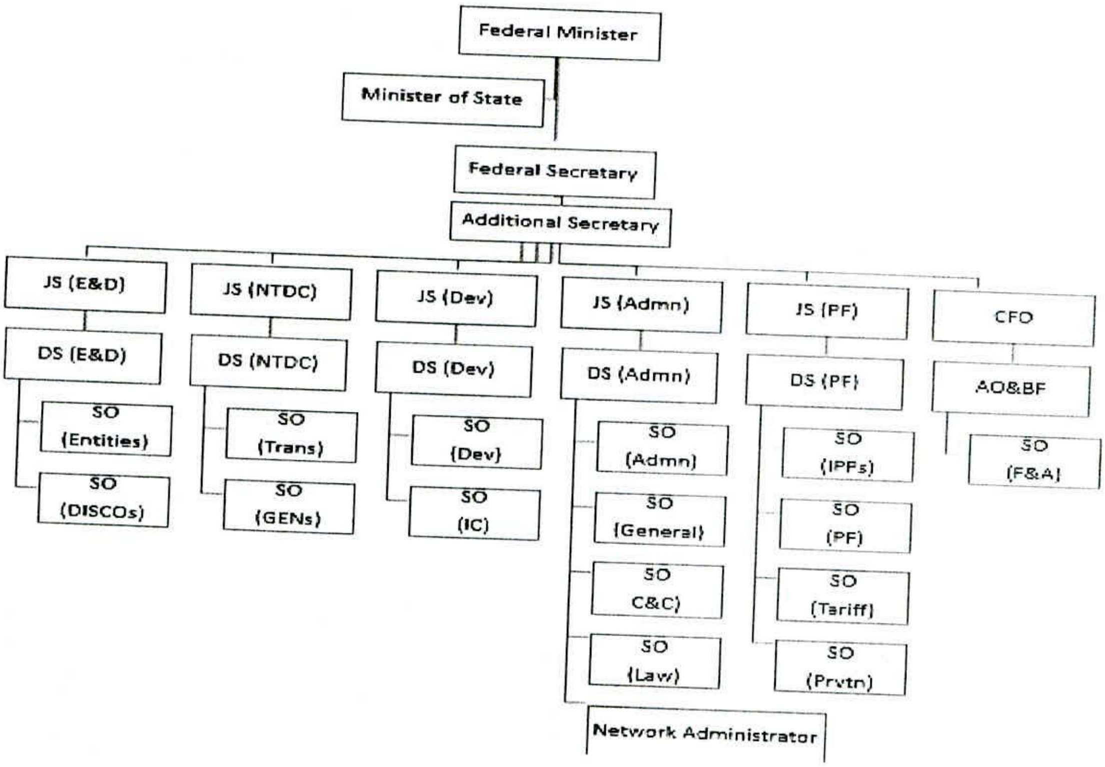
525. In this regard, the Power Division of the Ministry of Energy is the key administrative unit of the Federal Government which is responsible for matters related to the development of power resources of the country and is therefore most suited to take this responsibility and ensure the performance of these tasks.

526. Within the Division, either the Minister-in-Charge or Secretary Power may be assigned this responsibility and progress thereon should be reported on a regular basis to the Cabinet. Full support also has to be provided by the Cabinet to the Power Division, both technical and financial, so that they are effectively able to implement the plan.

527. In this regard, the following outlines a proposed restructuring of the Power Division wherein they will be enabled to hire and utilize in-house expertise.

Current Organogram of Power Division

528. A closer look at the organogram of the Power Division[73] shows that the current organization structure is geared towards an entity-based structure and not function based. This is despite the fact that different kind of specialized knowledge is required to manage the national power policies, plans and sector, which includes expertise in finance, legal, energy economics, etc.



Strengthening the Power Division – Proposed Organogram

529. A restructuring plan was prepared in 2017 by the then Minister for Power, acknowledging the need to strengthen the Division through hiring of professionals having sound knowledge and pertinent experience by offering them market-based compensation packages.

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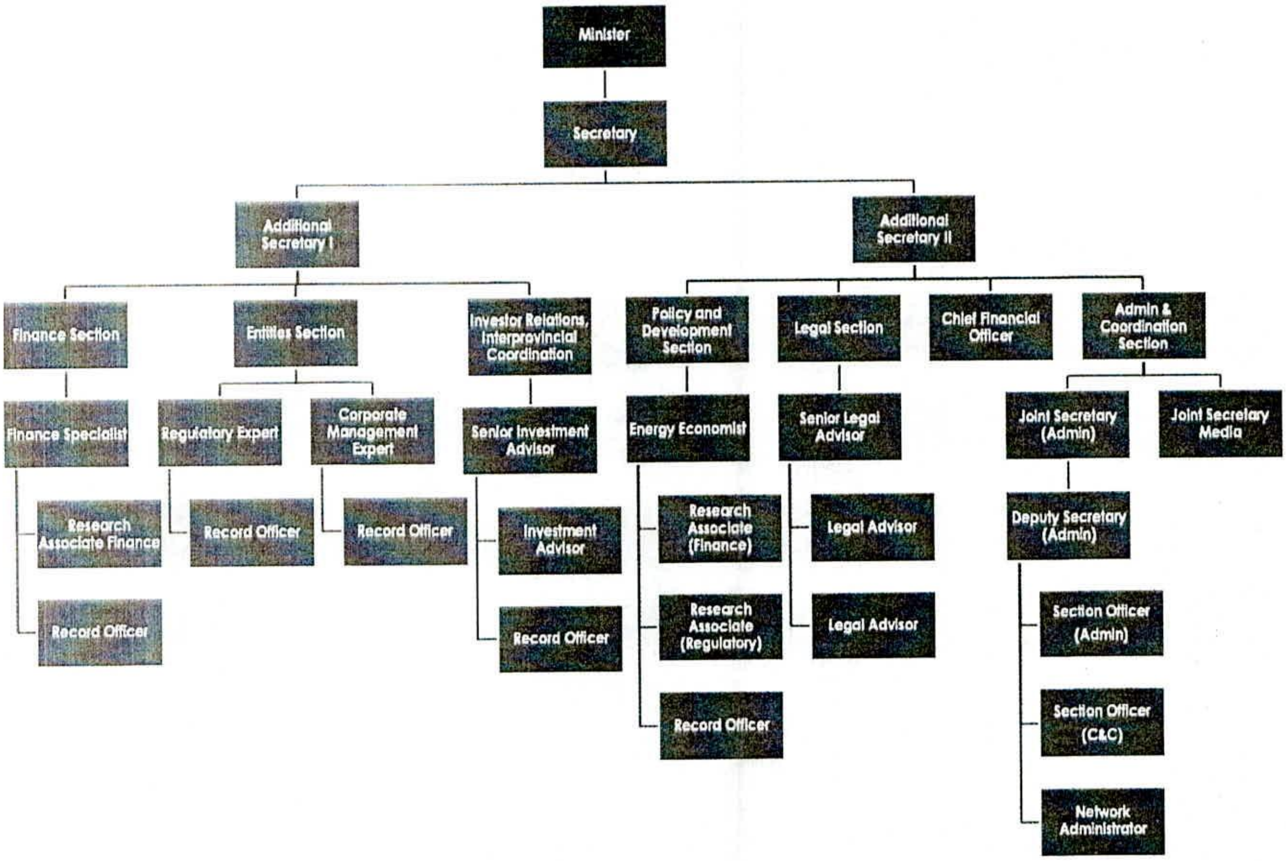
[73] This organogram is from the year 2017

530. The proposed organogram of the 2017 restructuring plan is:



531. This organogram is structured on a functional basis, thereby ensuring the availability of specialized knowledge of each function, as well as clear segregation of responsibilities. This will allow decision making to be based on expert input. The salient features of this restructuring are:

- Finance specialists responsible for matters related to management of subsidies, tariff issues, coordination with the power purchasers, and eventual elimination of the circular debt;
- Regulatory experts assisting the division and Federal Government in ensuring regulatory compliance and dealing with issues pertaining to DISCOs, NTDC, GENCOs, appointments in respective boards, etc.;
- Policy experts and energy economists responsible for drafting the national electricity policy and plan;

- Lawyers providing in-house support in managing the sector's contracting matters, litigation, arbitration, etc.; and
- Officers with experience of dealing in government matters responsible for interprovincial coordination, CPEC projects, net-hydel profit issues, etc.

532. This restructuring is not new to the Federal Government. Currently, the Privatization Commission is organized along similar lines, staffing experts from different areas having sector-specific knowledge who can manage complex privatization transactions.

533. Moving forward with a renewed vigor to address the issues faced by the nation's power sector, approving this implementation plan as well as strengthening and restructuring of MoE (Power Division) may be the most important steps in the right direction.

SECTION 5 – IPP WISE REPORTS

THERMAL PLANTS - 2002 POWER POLICY

Attock Generation Limited

Background	
Date of Incorporation	December 1, 2005
Ownership Structure	Subsidiary of Attock Oil Company Limited, UK Ultimate parent is Bay View International Group S.A.
Size of Plant	165 MW
Location of Plant	Morgah, Rawalpindi
CoD	March 17, 2009
Term of PPA	25 Years

Details of Tariff	
Tariff Petition Submitted on	November 2005
Tariff Petition Admitted on	June 2006
Tariff Granted on	September 4, 2006
Tariff Control Period allowed	25 years
Project Cost claimed	USD 150.034 million
Project Cost allowed	USD 148.601 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*126.600 million*
	Import Duties etc.	*6.510 million*
	Emergency Spare Parts	*1.890 million*
	Mobilization Cost	*0.910 million*
	Project Development Cost	*2.050 million*
	Admin and Utilities	*0.750 million*
	Financing Fees & Charges	*2.494 million*
	Interest During Construction	*7.396 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 04-09-2006**	**COD Determination 30-07-2009**
	Equity	*29.720*	*31.024*
	Total debt	*118.880*	*124.095*
	Total Project Cost	*148.600*	*155.119*
	Debt to Equity Ratio	*80:20*	*80:20*

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 04-09-2006**	**COD Determination 30-07-2009**
	EPC Cost	126.600[74]	122.148[75]
	EPC Cost – break-up in currencies - Euros	US$105.50	
	Other costs	14.605	13.809
	Total Capital Cost	**141.543**	**135.957**
	Interest During Construction (IDC)	7.396	19.162
	Total Project Cost	**148.601**	**155.119**
	USD/EURO parity rate	1.20	1.4183
	Output of the plant	**156.138MW**	**156.181MW**

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[74] As the timing of exact payment to contractor was unknown, therefore, adjustment for the relevant foreign currency fluctuations allowed.

[75] The Authority allowed adjustment in EPC cost due to foreign currency fluctuation

REVIEW OF PROFITABILITY AND DIVIDENDS

534. To determine the profitability and dividend history of AGL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period March 17, 2009 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends ***17.3.2009 till 30.6.2018***	
Capital Injected by Sponsors	Rs. 3.0 billion
Allowed Regulated Profit	Rs.5.78 billion @15% USD equity IRR
Profit Recorded FY2010 to FY2018	Rs. 26.76 billion
Profit after adjustment	Rs. 19.59 billion
Excess Profit	Rs.13.81 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 20.70 billion
Equity Payback after CoD	1 – 2 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

535. A comparison of Adjusted Profits with allowed regulatory returns during the period July 1, 2010 to June 30, 2018 revealed that AGL has earned an excess profit of **Rs.13.81 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2010 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**	**Total**
Adjusted Profit Working										
Accounting Profit Before Tax	2.975	2.531	2.462	2.851	3.761	3.745	3.146	2.817	2.473	26.760
Depreciation	0.481	0.477	0.478	0.482	0.483	0.489	0.487	0.485	0.478	4.340
Finance Cost Long term	0.195	0.318	0.460	0.743	0.874	1.030	1.328	1.454	1.481	7.884
Debt Service Cost	(1.789)	(1.707)	(1.656)	(1.783)	(1.771)	(1.798)	(2.000)	(2.04)	(1.579)	(16.12)
Cost of WC as per CPPA	(0.060)	(0.060)	(0.060)	(0.060)	(0.060)	(0.060)	(0.061)	(0.06)	(0.060)	(0.543)
LPS Energy Purchase Price	0.172	0.113	(0.020)	(0.079)	(0.183)	0.008	(0.090)	(0.13)	-	(0.209)
LPS Capacity Purchase Price	(0.189)	(0.121)	(0.085)	(0.198)	(0.179)	(0.465)	(0.208)	(0.16)	-	(1.607)
Finance Cost Short Term	0.003	0.006	0.009	0.011	0.013	0.014	0.015	0.016	0.018	0.105
Capitalized Spares	(0.001)	(0.095)	-	-	-	(0.006)	(0.009)	(.002)	(0.023)	(0.135)
Donation	0.001	0.001	0.001	0.001	0.002	0.003	0.000	0.000	0.000	0.009
Other Income	(0.137)	(0.078)	(0.090)	(0.104)	(0.112)	(0.112)	(0.139)	(0.12)	(0.003)	(0.895)
Adjusted Profit	1.651	1.385	1.499	1.864	2.826	2.847	2.469	2.263	2.786	**19.590**
Allowed Regulatory Return	0.740	0.714	0.705	0.689	0.695	0.655	0.606	0.585	0.387	**5.776**
Excess return	**0.911**	**0.671**	**0.793**	**1.175**	**2.131**	**2.193**	**1.862**	**1.678**	**2.399**	**13.814**

DETAILS OF SAVINGS IN FUEL COST

536. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.8.87 billion, which has ultimately contributed towards an excess profit of Rs.13.81 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 110.71 billion
Fuel Cost incurred	Rs. 101.84 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 8.87 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2009-10	8.744	1.230	10.753	9.655	1.097
FY 2010-11	10.488	1.203	12.612	11.584	1.028
FY 2011-12	14.560	1.172	17.070	15.566	1.504
FY 2012-13	13.924	1.255	17.476	16.034	1.442
FY 2013-14	14.136	1.243	17.570	16.127	1.443
FY 2014-15	10.370	1.209	12.537	11.675	0.862
FY 2015-16	5.268	1.179	6.212	5.784	0.428
FY 2016-17	6.962	1.135	7.904	7.440	0.464
FY 2017-18	9.400	0.912	8.573	7.974	0.599
Total FY 2010-2018	**93.846**	**10.539**	**110.707**	**101.839**	**8.868**

DETAILS OF SAVINGS IN O&M EXPENSES

537. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.3.82 billion, which has ultimately contributed towards the excess profit of Rs.13.81 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.12.15 billion
O&M Expenses incurred	Rs.8.33 billion
Difference in Allowed and Incurred O&M Expenses	Rs.3.82 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2009-10	1.230	0.657	0.250	0.906	0.392	0.514
FY 2010-11	1.203	0.805	0.327	1.132	0.541	0.591
FY 2011-12	1.172	0.860	0.362	1.222	0.912	0.310
FY 2012-13	1.255	1.006	0.388	1.394	0.705	0.689
FY 2013-14	1.243	1.083	0.429	1.512	0.880	0.632
FY 2014-15	1.209	1.071	0.442	1.513	1.248	0.265
FY 2015-16	1.179	1.079	0.454	1.533	1.200	0.333
FY 2016-17	1.135	1.068	0.469	1.537	1.384	0.153
FY 2017-18	0.912	0.905	0.491	1.396	1.071	0.325
Total FY 2010-2018	**10.539**	**8.534**	**3.612**	**12.146**	**8.335**	**3.811**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.36 billion
Additional Profitability over Remaining Life of Contract	Rs.0.64 billion
Additional Profitability over Life of Project	Rs.1 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.14 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings							
Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
9	8.87	3.81	1.13	0.36	0.14	-	14.31

Liberty Power Tech Limited

Background	
Date of Incorporation	September 13, 2007
Ownership Structure	Subsidiary of Liberty Mills Limited
Size of Plant	200 MW
Location of Plant	Faisalabad
CoD	January 13, 2011
Term of PPA	25 Years
Details of Tariff	
Tariff Petition Submitted on	November 2007
Tariff Petition Admitted on	November 2007
Tariff Granted on	February 28, 2008
Tariff Control Period allowed	25 years
Project Cost claimed	USD 150.034 million
Project Cost allowed	USD 148.601 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*197.961 million*
	Other Costs	*28.002 million*
	Interest During Construction	*13.848 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 28-02-2008**	**COD Determination 17-08-2011**
	Equity	59.953	60.06
	Total debt	179.858	180.18
	Total Project Cost	239.811	240.24
	Debt to Equity Ratio	75:25	75:25

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 28-02-2008**	**COD Determination 17-08-2011**
	EPC Cost	197.961	185.65
	Other costs	28.002	28.88
	Interest During Construction (IDC)	13.848	25.71
	Total Project Cost	**239.811**	**240.24**
	USD/EURO parity rate	1.20	1.4582
	Output of the plant	**200MW**	**196.139MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

538. To determine the profitability and dividend history of LPTL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period January 13, 2011 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends
13.1.2011 till 30.6.2018

Capital Injected by Sponsors	Rs. 5.05 billion
Allowed Regulated Profit	Rs.7.52 billion @15% USD equity IRR
Profit Recorded FY2010 to FY2018	Rs. 23.97 billion
Profit after adjustment	Rs. 19.84 billion
Excess Profit	Rs.12.32 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 17.89 billion
Equity Payback after CoD	2 – 3 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

539. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that LPTL has earned an excess profit of **Rs.12.32 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	3.545	3.902	3.508	3.691	3.208	2.961	2.157	0.998	23.969
Depreciation	1.133	1.277	1.280	1.373	1.516	1.438	1.501	0.418	9.936
Debt Service Cost	(2.550)	(2.415)	(2.368)	(2.613)	(2.390)	(2.468)	(2.928)	(0.98)	(18.72)
Finance Cost long term	0.724	0.863	1.052	1.507	1.657	1.855	2.317	1.149	11.124
Cost of WC as CPPA	(0.207)	(0.203)	(0.216)	(0.287)	(0.270)	(0.286)	(0.364)	(0.10)	(1.934)
LPS Total	(0.751)	(0.457)	(0.452)	(0.717)	(0.587)	(0.963)	(1.181)	-	(5.108)
Finance Cost Short Term	0.519	0.131	0.104	0.345	0.353	0.602	0.954	0.366	3.374
Capitalized Spares (P&M)	(0.803)	(0.370)	(0.455)	(0.042)	(0.418)	(0.132)	(0.151)	-	(2.370)
Donation	0.003	0.003	0.132	0.058	0.020	0.005	0.001	0.003	0.224
Impairment	0.036	0.053	-	-	-	-	0.001	-	0.090
Other Income	(0.000)	(0.500)	(0.127)	(0.092)	(0.008)	(0.001)	(0.012)	(0.01)	(0.748)
Adjusted Profit as per FS	1.651	2.284	2.458	3.222	3.082	3.011	2.294	1.835	**19.835**
Allowed Regulatory Return	1.146	1.102	1.093	1.058	0.982	0.945	0.900	0.291	**7.516**
Excess return	**0.504**	**1.182**	**1.366**	**2.164**	**2.100**	**2.065**	**1.394**	**1.544**	**12.319**

DETAILS OF SAVINGS IN FUEL COST

540. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.4.33 billion, which has ultimately contributed towards an excess profit of Rs.12.32 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 113.32 billion
Fuel Cost incurred	Rs. 108.99 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 4.33 billion**

Details of Fuel Savings

Year	EPP (CPPA)			FS IPP	Fuel Savings
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2010-11	11.4343	0.745	8.521	8.300	0.221
FY 2011-12	14.0405	1.068	15.002	14.352	0.650
FY 2012-13	14.1599	1.438	20.367	19.623	0.744
FY 2013-14	14.4154	1.520	21.905	21.025	0.880
FY 2014-15	11.5187	1.515	17.446	16.494	0.951
FY 2015-16	6.9055	1.250	8.631	8.085	0.546
FY 2016-17	7.7603	1.340	10.397	10.186	0.211
FY 2017-18	9.3997	1.176	11.050	10.927	0.124
Total FY 2011-2018		**10.051**	**113.318**	**108.992**	**4.327**

DETAILS OF SAVINGS IN O&M EXPENSES

541. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.5.54 billion, which has ultimately contributed towards the excess profit of Rs.12.32 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.12.88 billion
O&M Expenses incurred	Rs.7.34 billion
Difference in Allowed and Incurred O&M Expenses	Rs.5.54 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2010-11	0.745	0.564	0.137	0.700	0.254	0.446
FY 2011-12	1.068	0.857	0.378	1.235	0.595	0.640
FY 2012-13	1.438	1.283	0.394	1.678	0.783	0.895
FY 2013-14	1.520	1.449	0.424	1.874	1.116	0.758
FY 2014-15	1.515	1.472	0.473	1.945	0.879	1.066
FY 2015-16	1.250	1.253	0.489	1.743	1.032	0.711
FY 2016-17	1.340	1.383	0.504	1.887	1.161	0.726
FY 2017-18	1.176	1.284	0.531	1.815	1.524	0.290
Total FY 2011-2018	**10.051**	**9.546**	**3.330**	**12.876**	**7.343**	**5.533**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.47 billion
Additional Profitability over Remaining Life of Contract	Rs.1 billion
Additional Profitability over Life of Project	Rs.1.47 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.2 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF SHORTFALL IN INVENTORY

Shortfall in Inventory	
Inventory Level Required by NEPRA	27,570 tonnes
Average Quantity Maintained	14,862 tonnes
Benefit of Maintaining Lower Inventory Levels	Rs.0.64 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
8	**Rs. in Billion**						
	4.33	5.53	2.46	0.47	0.2	0.64	13.63

Nishat Chunian Power Limited

Background	
Date of Incorporation	February 23, 2007
Ownership Structure	Subsidiary of Nishat (Chunian) Limited
Size of Plant	200 MW
Location of Plant	Near Lahore
CoD	July 21, 2010
Term of PPA	25 Years

Details of Tariff	
Tariff Petition Submitted on	January 2007
Tariff Control Period allowed	25 years
Project Cost allowed	USD 203.841 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*160.170 million*
	Other Costs	*29.027 million*
	Interest During Construction	*14.644 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 15-01-2007**	**COD Determination 31-12-2010**
	Equity	50.960	47.481
	Total debt	152.881	189.925
	Total Project Cost	203.841	237.406
	Debt to Equity Ratio	75:25	80:20

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 15-01-2007**	**COD Determination 31-12-2010**
	EPC Cost	160.170	185.810
	Other costs	29.027	-
	Interest During Construction (IDC)	14.644	29.587
	Total Project Cost	**203.841**	**237.406**
	USD/EURO parity rate	1.20	1.4183
	Output of the plant	**200MW**	**195.722MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

542. To determine the profitability and dividend history of NCPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period July 21, 2010 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends ***21.7.2011 till 30.6.2018***	
Capital Injected by Sponsors	Rs. 3.67 billion
Allowed Regulated Profit	Rs.6.52 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 21.51 billion
Profit after adjustment	Rs. 15.82 billion
Excess Profit	Rs.9.30 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 12.95 billion
Equity Payback after CoD	2 – 3 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

543. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that NCPL has earned an Excessive Profit of **Rs.9.30 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	3.406	2.998	2.756	3.090	2.901	2.713	2.016	1.626	21.507
Depreciation	1.066	1.153	1.171	1.142	1.161	1.103	0.955	1.255	9.006
Debt Service Cost	(2.604)	(2.481)	(2.445)	(2.675)	(2.645)	(2.416)	(2.684)	(2.90)	(20.85)
Finance Cost Long Term	0.584	0.742	0.938	1.388	1.554	1.769	2.246	2.345	11.567
Cost of WC as CPPA	(0.190)	(0.186)	(0.199)	(0.264)	(0.267)	(0.249)	(0.298)	(0.32)	(1.974)
LPS Energy Purchase Price	(0.403)	(0.281)	(0.304)	(0.330)	(0.324)	(0.606)	(0.834)	(0.45)	(3.530)
LPS Capacity Purchase Price	(0.173)	(0.102)	(0.040)	(0.339)	(0.227)	(0.351)	(0.231)	(0.09)	(1.549)
Finance Cost Short Term	0.462	0.350	0.281	0.497	0.368	0.655	0.834	0.595	4.042
Capitalized Spares	(0.464)	(0.556)	(0.385)	(0.298)	(0.470)	(0.040)	-	-	(2.214)
Donation	0.005	0.085	0.086	0.035	0.051	0.004	0.000	0.002	0.268
Other Income	(0.036)	(0.036)	(0.028)	(0.029)	(0.086)	(0.156)	(0.034)	(0.05)	(0.449)
Adjusted Profit as Per F.S	1.654	1.685	1.831	2.217	2.015	2.424	1.971	2.026	**15.824**
Allowed Regulatory Return	0.930	0.893	0.889	0.859	0.860	0.734	0.661	0.696	**6.522**
Excess return	**0.724**	**0.792**	**0.942**	**1.359**	**1.155**	**1.691**	**1.310**	**1.329**	**9.302**

DETAILS OF SAVINGS IN FUEL COST

544. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.3.02 billion, which has ultimately contributed towards an excess profit of Rs.9.30 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 114.83 billion
Fuel Cost incurred	Rs. 111.81 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 3.02 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2010-11	11.3655	1.320	15.005	14.026	0.978
FY 2011-12	13.9715	1.073	14.985	14.595	0.390
FY 2012-13	14.5053	1.283	18.610	18.254	0.356
FY 2013-14	14.3073	1.471	21.052	20.772	0.281
FY 2014-15	11.3430	1.415	16.054	15.634	0.420
FY 2015-16	7.0357	1.208	8.501	8.083	0.418
FY 2016-17	7.7853	1.316	10.244	10.143	0.102
FY 2017-18	9.4357	1.100	10.376	10.303	0.073
Total FY 2011-2018	**11.2728**	**10.186**	**114.828**	**111.810**	**3.018**

DETAILS OF SAVINGS IN O&M EXPENSES

545. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.5.01 billion, which has ultimately contributed towards the excess profit of Rs.9.30 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.12.05 billion
O&M Expenses incurred	Rs.7.04 billion
Difference in Allowed and Incurred O&M Expenses	Rs.5.01 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2010-11	1.452	0.807	0.336	1.142	0.417	0.725
FY 2011-12	1.073	0.773	0.351	1.123	0.803	0.320
FY 2012-13	1.283	1.028	0.390	1.418	0.704	0.714
FY 2013-14	1.471	1.260	0.465	1.726	1.185	0.541
FY 2014-15	1.415	1.231	0.483	1.714	0.943	0.771
FY 2015-16	1.208	1.085	0.501	1.586	0.783	0.803
FY 2016-17	1.316	1.215	0.515	1.730	1.099	0.631
FY 2017-18	1.100	1.068	0.541	1.610	1.102	0.508
Total FY 2011-2018	**10.318**	**8.468**	**3.582**	**12.050**	**7.037**	**5.013**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.41 billion
Additional Profitability over Remaining Life of Contract	Rs.0.87 billion
Additional Profitability over Life of Project	Rs.1.27 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.21 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF SHORTFALL IN INVENTORY

Shortfall in Inventory	
Inventory Level Required by NEPRA	27,885 tonnes
Average Quantity Maintained	12,910 tonnes
Benefit of Maintaining Lower Inventory Levels	Rs.0.57 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
8	3.02	5.01	1.27	0.41	0.21	0.57	10.49

Nishat Power Limited

Background	
Date of Incorporation	February 23, 2007
Ownership Structure	Subsidiary of Nishat Mills Limited
Size of Plant	200 MW
Location of Plant	Pattoki District Kasur
CoD	June 9, 2010
Term of PPA	25 Years
Details of Tariff	
Tariff Petition Submitted on	January 2007
Tariff Petition Admitted on	January 2007
Tariff Petition Granted on	March 2007
Tariff Control Period allowed	25 years
Project Cost allowed	USD 204.029 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*169.567 million*
	Other Costs	*22.949 million*
	Interest During Construction	*11.513 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 06-03-2007**	**COD Determination 15-10-2010**
	Equity	40.806	45.733
	Total debt	163.223	182.934
	Total Project Cost	204.029	228.667
	Debt to Equity Ratio	80:20	80:20

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 06-03-2007**	**COD Determination 15-10-2010**
	EPC Cost	169.567	181.071
	Other costs	22.949	21.47
	Interest During Construction (IDC)	11.513	26.126
	Total Project Cost	**204.029**	**228.667**
	USD/EURO parity rate	1.20	1.3779
	Output of the plant	**200MW**	**195.305MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

546. To determine the profitability and dividend history of NPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period June 9, 2010 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends
9.6.2010 till 30.6.2018

Capital Injected by Sponsors	Rs. 3.54 billion
Allowed Regulated Profit	Rs.6.17 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 21.61 billion
Profit after adjustment	Rs. 14.62 billion
Excess Profit	Rs.8.45 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 8.85 billion
Equity Payback after CoD	2 – 3 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

547. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that NPL has earned an Excessive Profit of **Rs.8.45 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	3.211	2.884	2.851	3.117	2.917	2.702	2.035	1.893	21.611
Depreciation	0.976	0.984	1.006	1.014	1.071	1.066	0.971	1.206	8.295
Debt Service Cost	(2.363)	(2.183)	(2.232)	(2.456)	(2.466)	(2.340)	(2.414)	(2.59)	(19.04)
Finance Cost Long Term	0.534	0.677	0.858	1.267	1.418	1.620	2.104	2.320	10.797
Cost of WC as CPPA	(0.195)	(0.185)	(0.206)	(0.275)	(0.282)	(0.274)	(0.304)	(0.31)	(2.031)
LPS Energy Purchase Price	(0.506)	(0.280)	(0.327)	(0.443)	(0.370)	(0.621)	(0.725)	(0.4)	(3.743)
LPS Capacity Purchase Price	(0.194)	(0.139)	(0.089)	(0.218)	(0.208)	(0.352)	(0.267)	(0.13)	(1.594)
Finance Cost Short Term	0.204	0.072	0.009	0.162	0.194	0.621	0.776	0.595	2.631
Capitalized Spares	(0.118)	(0.715)	(0.192)	(0.007)	(0.491)	(0.131)	(0.034)	(0.30)	(1.992)
Donation	-	-	-	-	0.003	-	-	0.002	0.005
Other Income	(0.051)	(0.023)	(0.034)	(0.034)	(0.030)	(0.049)	(0.067)	(0.03)	(0.314)
Adjusted Profit	1.498	1.092	1.644	2.128	1.756	2.242	2.075	2.187	**14.622**
Allowed Regulatory Return	0.876	0.816	0.843	0.819	0.834	0.736	0.617	0.629	**6.168**
Excess return	**0.622**	**0.275**	**0.802**	**1.309**	**0.922**	**1.506**	**1.459**	**1.559**	**8.454**

DETAILS OF SAVINGS IN FUEL COST

548. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.3.36 billion, which has ultimately contributed towards an excess profit of Rs.8.45 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits					
Fuel Cost allowed	Rs. 115.40 billion				
Fuel Cost incurred	Rs. 112.04 billion				
Difference in Allowed and Incurred Fuel Cost	**Rs. 3.36 billion**				
Details of Fuel Savings					
Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2010-11	11.3655	1.320	15.005	14.026	0.978
FY 2010-11	10.2684	1.562	16.035	14.388	1.647
FY 2011-12	14.1660	1.063	15.055	14.502	0.553
FY 2012-13	13.9922	1.276	17.860	18.262	(0.402)
FY 2013-14	14.4784	1.464	21.198	20.750	0.448
FY 2014-15	11.3797	1.410	16.043	15.602	0.441
FY 2015-16	6.8617	1.272	8.729	8.292	0.437
FY 2016-17	7.7063	1.240	9.554	9.363	0.191
FY 2017-18	9.3325	1.171	10.930	10.882	0.048
Total FY 2011-2018	**11.0353**	**10.458**	**115.404**	**112.042**	**3.362**

DETAILS OF SAVINGS IN O&M EXPENSES

549. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.3.88 billion, which has ultimately contributed towards the excess profit of Rs.8.45 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits

O&M Expenses allowed	Rs.12.31 billion
O&M Expenses incurred	Rs.8.42 billion
Difference in Allowed and Incurred O&M Expenses	Rs.3.88 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2010-11	1.562	1.040	0.328	1.368	0.771	0.598
FY 2011-12	1.063	0.767	0.339	1.106	0.648	0.458
FY 2012-13	1.276	1.023	0.401	1.424	0.811	0.613
FY 2013-14	1.464	1.257	0.473	1.730	1.478	0.252
FY 2014-15	1.410	1.229	0.484	1.712	1.027	0.685
FY 2015-16	1.272	1.145	0.498	1.643	0.942	0.701
FY 2016-17	1.240	1.147	0.494	1.641	1.627	0.014
FY 2017-18	1.171	1.146	0.535	1.681	1.118	0.562
Total FY 2011-2018	**10.458**	**8.754**	**3.552**	**12.306**	**8.423**	**3.883**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%

NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.45 billion
Additional Profitability over Remaining Life of Contract	Rs.0.96 billion
Additional Profitability over Life of Project	Rs.1.41 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments

NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.20 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF SHORTFALL IN INVENTORY

Shortfall in Inventory	
Inventory Level Required by NEPRA	22,662 tonnes
Average Quantity Maintained	17,514 tonnes
Benefit of Maintaining Lower Inventory Levels	Rs.0.22 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
8	3.36	3.88	1.21	0.45	0.2	0.22	9.33

Uch-II Power Limited

Background			
Date of Incorporation	October 8, 2008		
Ownership Structure	Subsidiary of Engie Energy International		
Size of Plant	404 MW		
Location of Plant	Dera Murad Jamali		
CoD	April 4, 2014		
Term of PPA	25 Years		
Details of Tariff			
Tariff Petition Submitted on	November 2008		
Tariff Petition Admitted on	December 2008		
Tariff Petition Granted on	April 2009		
Tariff Control Period allowed	25 years		
Project Cost allowed	USD 471.132 million		
IRR Allowed	USD based equity - 15%		
Breakdown of Project Cost allowed (USD)	EPC	*366.764 million*	
	Other Costs	*66.008 million*	
	Interest During Construction	*38.360 million*	
Capital Structure and Project set-up cost (USD million)		**Tariff Determination 14-04-2009**	**COD Determination 03-07-2017**
	Equity	117.783	115.516
	Total debt	353.349	345.442
	Total Project Cost	471.132	460.958
	Debt to Equity Ratio	75:25	74.94:25.06
Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 14-04-2009**	**COD Determination 03-07-2017**
	EPC Cost	366.764	368.043
	Other costs	66.008	65.372
	Interest During Construction (IDC)	38.360	27.543
	Total Project Cost	**471.132**	**460.958**
	Output of the plant	**375.20MW**	**380.75MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

550. To determine the profitability and dividend history of UCH-II, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period April 4, 2014 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends ***04.04.2014 till 30.6.2018***	
Capital Injected by Sponsors	Rs. 11.20 billion
Allowed Regulated Profit	Rs.9.79 billion @15% USD equity IRR
Profit Recorded FY2014 to FY2018	Rs. 20.71 billion
Profit after adjustment	Rs. 16.87 billion
Excess Profit	Rs.7.08 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 6.59 billion
Equity Payback after CoD	3 – 4 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

551. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2014 to June 30, 2018 revealed that UCH-II has earned an Excessive Profit of **Rs.7.08 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2014 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**Total**
Adjusted Profit Working						
Accounting Profit Before Tax	5.615	3.915	4.576	4.726	1.881	20.713
Depreciation	1.732	1.558	1.530	1.497	1.148	7.465
Debt Service Cost	(4.377)	(3.870)	(3.668)	(3.220)	(0.838)	(15.973)
Finance Cost long term	1.802	1.148	1.241	1.185	0.968	6.344
LPS	(0.355)	(0.239)	(0.120)	(0.097)	(0.108)	(0.919)
Finance Cost Short Term	0.019	0.011	0.012	0.011	0.049	0.102
Capitalized Spares (P&M)	(0.015)	(0.044)	(0.040)	(0.007)	-	(0.107)
Donation	-	-	-	-	-	-
Other Income	(0.316)	(0.307)	(0.212)	0.007	0.068	(0.760)
Adjusted Profit as per FS	4.107	2.172	3.318	4.102	3.167	**16.865**
Allowed Regulatory Return	2.487	2.387	2.345	2.055	0.511	**9.785**
Excess return	**1.619**	**(0.216)**	**0.974**	**2.047**	**2.656**	**7.080**

DETAILS OF SAVINGS IN FUEL COST

552. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.2.54 billion, which has ultimately contributed towards an excess profit of Rs.7.08 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 60.01 billion
Fuel Cost incurred	Rs. 57.47 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 2.54 billion**
Details of Fuel Savings	

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2013-14	4.4594	1.998	8.909	7.694	1.215
FY 2014-15	4.8189	2.313	11.148	11.814	(0.666)
FY 2015-16	4.9206	2.414	11.879	11.291	0.588
FY 2016-17	4.9692	2.526	12.550	11.937	0.613
FY 2017-18	9.4357	2.892	15.526	14.735	0.791
Total FY 2014-2018	**4.9420**	**12.143**	**60.012**	**57.471**	**2.541**

DETAILS OF SAVINGS IN O&M EXPENSES

553. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.2.70 billion, which has ultimately contributed towards the excess profit of Rs.7.08 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.7.63 billion
O&M Expenses incurred	Rs.4.93 billion
Difference in Allowed and Incurred O&M Expenses	Rs.2.70 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2013-14	1.998	0.409	0.627	1.036	0.586	0.450
FY 2014-15	2.313	0.485	0.990	1.475	0.832	0.642
FY 2015-16	2.414	0.523	1.042	1.565	1.049	0.516
FY 2016-17	2.526	0.561	1.081	1.642	1.137	0.505
FY 2017-18	2.892	0.728	1.184	1.912	1.328	0.584
Total FY 2014-2018	**12.143**	**2.707**	**4.923**	**7.630**	**4.931**	**2.698**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.61 billion
Additional Profitability over Remaining Life of Contract	Rs.2.45 billion
Additional Profitability over Life of Project	Rs.3.06 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.09 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	Fuel Cost	O&M	Un-identified	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
	Rs. in Billion						
5	2.54	2.70	1.84	0.61	0.09	-	7.79

Atlas Power Limited

Background	
Date of Incorporation	January 5, 2007
Ownership Structure	Subsidiary of Shirazi Investments (Private) Limited
Size of Plant	225 MW
Location of Plant	Lahore Sheikhupura Road
CoD	December 18, 2009
Term of PPA	25 Years

Details of Tariff	
Tariff Petition Submitted on	January 2007
Tariff Petition Admitted on	January 2007
Tariff Petition Granted on	March 2007
Tariff Control Period allowed	25 years
Project Cost allowed	USD 224.42 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*190.01 million*
	Other Costs	*23.87 million*
	Interest During Construction	*10.54 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 06-03-2007**	**COD Determination 19-05-2010**
	Equity	56.11	63.85
	Total debt	168.32	190.934
	Total Project Cost	224.42	253.85
	Debt to Equity Ratio	75:25	75:25

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 06-03-2007**	**COD Determination 19-05-2010**
	EPC Cost	190.01	207.07
	Other costs	23.87	26.99
	Interest During Construction (IDC)	10.54	19.79
	Total Project Cost	**224.42**	**253.85**

REVIEW OF PROFITABILITY AND DIVIDENDS

554. To determine the profitability and dividend history of APL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period December 18, 2009 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends
18.12.2009 till 30.6.2018

Capital Injected by Sponsors	Rs. 4.74 billion
Allowed Regulated Profit	Rs.8.12 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 18.75 billion
Profit after adjustment	Rs. 12.90 billion
Excess Profit	Rs.4.78 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 12.68 billion
Equity Payback after CoD	2 – 3 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

555. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that APL has earned an Excessive Profit of **Rs.4.78 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	3.180	3.308	3.144	2.290	2.183	1.836	1.443	1.367	18.750
Depreciation	0.793	0.792	0.791	0.794	0.794	0.791	0.791	0.803	6.348
Debt Service Cost	(2.467)	(2.343)	(2.277)	(2.488)	(2.457)	(2.334)	(2.262)	(2.78)	(19.40)
Finance Cost Long term	0.489	0.606	0.771	1.180	1.348	1.559	2.009	2.162	10.124
Cost of WC as CPPA	(0.212)	(0.208)	(0.221)	(0.295)	(0.299)	(0.291)	(0.305)	(0.38)	(2.207)
LPS Energy Purchase Price	(0.714)	(0.736)	(0.294)	(0.357)	(0.313)	(0.490)	(0.857)	(0.44)	(4.202)
LPS Capacity Purchase Price	(0.336)	(0.354)	(0.267)	(0.253)	(0.236)	(0.275)	(0.298)	(0.12)	(2.141)
Finance Cost Short Term	0.724	0.596	0.333	0.684	0.574	0.757	1.086	0.725	5.478
Capitalized Spares	-	(0.003)	-	-	-	(0.002)	-	-	(0.005)
Donation	0.034	0.032	0.024	0.023	0.019	0.015	0.014	0.006	0.167
Other Income	0.000	(0.001)	-	(0.001)	(0.008)	(0.000)	(0.000)	(0.00)	(0.010)
Adjusted Profit	1.491	1.688	2.003	1.577	1.606	1.566	1.620	1.347	**12.898**
Allowed Regulatory Return	1.161	1.115	1.109	1.073	1.076	0.952	0.750	0.886	**8.122**
Excess return	**0.329**	**0.573**	**0.894**	**0.504**	**0.530**	**0.614**	**0.871**	**0.461**	**4.776**

DETAILS OF SAVINGS IN FUEL COST

556. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.1.50 billion, which has ultimately contributed towards an excess profit of Rs.4.78 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 118.50 billion
Fuel Cost incurred	Rs. 117.00 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 1.50 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2009-10	9.0654	0.891	8.076	7.858	0.218
FY 2010-11	10.1499	1.484	15.062	14.987	0.075
FY 2011-12	14.0071	1.067	14.945	14.946	(0.001)
FY 2012-13	14.0984	1.383	19.498	19.175	0.323
FY 2013-14	14.3609	1.519	21.813	21.423	0.390
FY 2014-15	11.1051	1.462	16.232	15.856	0.376
FY 2015-16	6.5203	1.320	8.610	8.423	0.186
FY 2016-17	7.9280	1.337	10.599	10.510	0.089
FY 2017-18	9.4185	1.246	11.740	11.682	0.058
Total FY 2010-2018	**10.9536**	**10.818**	**118.498**	**117.002**	**1.496**

DETAILS OF SAVINGS IN O&M EXPENSES

557. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.1.70 billion, which has ultimately contributed towards the excess profit of Rs.4.78 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits

O&M Expenses allowed	Rs.12.75 billion
O&M Expenses incurred	Rs.11.05 billion
Difference in Allowed and Incurred O&M Expenses	Rs.1.70 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2009-10	0.891	0.516	0.139	0.654	0.738	(0.084)
FY 2010-11	1.484	0.990	0.366	1.356	1.003	0.353
FY 2011-12	1.067	0.768	0.332	1.101	1.179	(0.079)
FY 2012-13	1.383	1.093	0.418	1.511	1.552	(0.041)
FY 2013-14	1.519	1.303	0.492	1.795	1.735	0.061
FY 2014-15	1.462	1.274	0.510	1.784	1.721	0.063
FY 2015-16	1.230	1.109	0.524	1.633	1.037	0.597
FY 2016-17	1.337	1.237	0.542	1.779	1.306	0.473
FY 2017-18	1.246	1.220	0.571	1.790	1.520	0.270
Total FY 2010-2018	**10.728**	**8.995**	**3.755**	**12.750**	**11.052**	**1.698**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%

NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.51 billion
Additional Profitability over Remaining Life of Contract	Rs.1.08 billion
Additional Profitability over Life of Project	Rs.1.59 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments

NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.22 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF SHORTFALL IN INVENTORY

Shortfall in Inventory	
Inventory Level Required by NEPRA	30,024 tonnes
Average Quantity Maintained	9,212 tonnes
Benefit of Maintaining Lower Inventory Levels	Rs.0.97 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	Fuel Cost	O&M	Un-identified	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
	Rs. in Billion						
8	1.50	1.70	1.58	0.51	0.22	0.97	6.47

Engro Powergen Qadirpur Power Limited

Background	
Ownership Structure	Subsidiary of Engro Energy Limited
Size of Plant	227 MW
Location of Plant	Qadirpur Ghotki
CoD	March 27, 2010
Term of PPA	25 Years

Details of Tariff	
Tariff Petition Submitted on	February 2007
Tariff Petition Granted on	July 2007
Tariff Control Period allowed	25 years
Project Cost allowed	USD 204.668 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	_170.632 million_
	Other Costs	_19.053 million_
	Interest During Construction	_14.983 million_

		Tariff Determination 19-07-2007	**COD Determination 01-04-2011**
Capital Structure and Project set-up cost (USD million)	Equity	56.11	55.33
	Total debt	168.32	136.721
	Total Project Cost	204.668	192.051
	Debt to Equity Ratio	75:25	71.18:28.82

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 19-07-2007**	**COD Determination 01-04-2011**
	EPC Cost	170.632	160.335
	Other costs	19.053	22.70
	Interest During Construction (IDC)	14.983	9.016
	Total Project Cost	**204.668**	**192.051**
	Output of the plant	**216.80MW**	**217.298MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

558. To determine the profitability and dividend history of EPQL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period March 27, 2010 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends
27.03.2010 till 30.6.2018

Capital Injected by Sponsors	Rs. 3.24 billion
Allowed Regulated Profit	Rs.8.95 billion @15% USD equity IRR
Profit Recorded FY2010 to FY2018	Rs. 17.09 billion
Profit after adjustment	Rs. 11.98 billion
Excess Profit	Rs.3.03 billion (*Allowed Regulated Profit - Profit after adjustment*)
Amount withdrawn from Profits as Dividend	Rs. 8.70 billion
Equity Payback after CoD	2 – 3 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

559. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2010 to June 30, 2018 revealed that EPQL has earned an Excessive Profit of **Rs.3.03 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2010 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**	**Total**
Adjusted Profit Working										
Accounting Profit Before Tax	2.629	2.391	1.788	1.798	2.021	1.458	2.105	1.787	1.112	17.089
Depreciation	0.766	0.743	0.726	0.717	0.701	0.691	0.591	0.549	0.387	5.869
Finance Cost	0.547	0.409	0.401	0.484	0.561	0.881	0.836	0.563	0.378	5.060
Debt Service Cost	(1.882)	(1.704)	(1.684)	(1.598)	(1.604)	(1.257)	(1.541)	(1.40)	(1.047)	(13.71)
Cost of WC as CPPA	(0.061)	(0.057)	(0.058)	(0.068)	(0.085)	(0.064)	(0.099)	(0.11)	(0.079)	(0.680)
LPS Total	(0.343)	(0.268)	(0.111)	(0.161)	(0.092)	(0.119)	(0.657)	(0.27)	(0.129)	(2.153)
Finance Cost Short Term	0.189	0.148	0.113	0.153	0.196	0.218	0.335	0.279	0.164	1.796
Capitalized Spares (P&M)	(0.028)	(0.050)	(0.137)	(0.208)	(0.030)	(0.125)	(0.012)	(0.02)	-	(0.616)
Other Income	(0.002)	(0.110)	(0.099)	(0.007)	(0.154)	(0.410)	(0.003)	(0.02)	(0.011)	(0.817)
Donation	0.018	0.021	0.022	0.020	0.023	0.019	0.013	0.009	0.001	0.146
Adjusted Profit	1.834	1.522	0.961	1.130	1.536	1.293	1.567	1.363	0.776	**11.980**
Allowed Regulatory Return	1.202	1.099	1.096	1.056	1.062	0.830	1.005	0.915	0.687	**8.953**
Excess return	**0.632**	**0.423**	**(0.135)**	**0.074**	**0.473**	**0.462**	**0.561**	**0.448**	**0.088**	**3.028**

DETAILS OF SAVINGS IN FUEL COST

560. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.2.32 billion, which has ultimately contributed towards an excess profit of Rs.3.03 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 62.95 billion
Fuel Cost incurred	Rs. 60.63 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 2.32 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2009-10	2.8609	1.200	3.434	3.371	0.063
FY 2010-11	3.0334	1.665	5.051	4.981	0.070
FY 2011-12	4.5584	1.767	8.055	7.868	0.187
FY 2012-13	5.0378	1.334	6.718	5.443	1.275
FY 2013-14	4.7113	1.722	8.113	7.912	0.201
FY 2014-15	6.6398	1.424	9.455	9.258	0.198
FY 2015-16	5.5758	1.339	7.468	7.556	(0.089)
FY 2016-17	4.2586	1.737	7.399	7.199	0.200
FY 2017-18	4.7531	1.526	7.255	7.039	0.216
Total FY 2010-2018	**41.4292**	**13.715**	**62.947**	**60.626**	**2.321**

DETAILS OF SAVINGS IN O&M EXPENSES

561. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.0.34 billion, which has ultimately contributed towards the excess profit of Rs.3.03 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.7.74 billion
O&M Expenses incurred	Rs.7.40 billion
Difference in Allowed and Incurred O&M Expenses	Rs.0.34 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2009-10	1.200	0.190	0.221	0.411	0.352	0.060
FY 2010-11	1.665	0.428	0.360	0.787	0.522	0.266
FY 2011-12	1.767	0.481	0.372	0.852	0.574	0.278
FY 2012-13	1.334	0.396	0.326	0.722	0.982	(0.260)
FY 2013-14	1.722	0.539	0.445	0.984	0.847	0.138
FY 2014-15	1.424	0.454	0.451	0.905	1.065	(0.160)
FY 2015-16	1.339	0.442	0.471	0.913	1.060	(0.147)
FY 2016-17	1.737	0.588	0.490	1.078	0.952	0.126
FY 2017-18	1.526	0.582	0.502	1.083	1.043	0.041
Total FY 2010-2018	**13.715**	**4.099**	**3.638**	**7.737**	**7.396**	**0.341**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.56 billion
Additional Profitability over Remaining Life of Contract	Rs.0.99 billion
Additional Profitability over Life of Project	Rs.1.55 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.12 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings							
Years in Operation Since COD	Fuel Cost	O&M	Un-identified	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
	Rs. in Billion						
9	2.32	0.34	0.37	0.56	0.12	-	3.71

Foundation Power Company (Daharki) Limited

Background			
Ownership Structure	Subsidiary of Daharki Power Holdings Limited - British Virgin Island Ultimate parent is Fauji Foundation Pakistan		
Size of Plant	185 MW		
Location of Plant	Daharki Ghotki		
CoD	May 16, 2011		
Term of PPA	25 Years		
Details of Tariff			
Tariff Petition Submitted on	January 2006		
Tariff Petition Granted on	October 2006		
Tariff Control Period allowed	25 years		
Project Cost allowed	USD 202.844 million		
IRR Allowed	USD based equity - 15%		
Breakdown of Project Cost allowed (USD)	EPC	*156.730 million*	
	Other Costs	*21.459 million*	
	Interest During Construction	*24.655 million*	
Capital Structure and Project set-up cost (USD million)		**Tariff Determination 21-10-2006**	**COD Determination 28-11-2013**
	Equity	50.711	53.017
	Total debt	152.133	159.051
	Total Project Cost	202.844	212.068
	Debt to Equity Ratio	75:25	75:25
Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 21-10-2006**	**COD Determination 28-11-2013**
	EPC Cost	156.730	147.562
	Other costs	21.459	36.297
	Interest During Construction (IDC)	24.655	28.209
	Total Project Cost	**202.844**	**212.068**
	Output of the plant	**171.483MW**	**180.097MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

562. To determine the profitability and dividend history of FPCDL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period May 16, 2011 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends ***16.05.2011 till 30.6.2018***	
Capital Injected by Sponsors	Rs. 3.80 billion
Allowed Regulated Profit	Rs.6.40 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 8.93 billion
Profit after adjustment	Rs. 8.18 billion
Excess Profit	Rs.1.77 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 5.36 billion
Equity Payback after CoD	5 – 6 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

563. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that FPCDL has earned an Excessive Profit of **Rs.1.77 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	2.088	1.689	1.990	0.942	1.040	0.933	0.365	(0.116)	8.930
Depreciation	0.766	0.760	0.751	0.750	0.774	0.709	0.700	0.127	5.336
Finance Cost long term	0.674	0.801	0.986	1.897	1.463	1.794	2.032	0.272	9.917
Debt Service Cost	(1.894)	(1.871)	(1.877)	(2.079)	(2.001)	(2.229)	(2.281)	(0.277)	(14.51)
Cost of WC as CPPA	(0.037)	(0.037)	(0.040)	(0.046)	(0.044)	(0.055)	(0.057)	(0.008)	(0.325)
LPS charge	(0.281)	(0.286)	(0.229)	0.468	(0.176)	(0.655)	(0.368)	-	(1.527)
Finance Cost Short Term	0.002	0.018	0.033	0.042	0.055	0.050	0.052	0.010	0.262
Capitalized Spares (P&M)	-	(0.182)	(0.025)	(0.008)	-	-	(0.184)	-	(0.399)
Other Income	(0.031)	(0.053)	(0.063)	(0.070)	(0.096)	(0.044)	(0.002)	(0.006)	(0.365)
Impairment	-	-	-	0.100	-	-	0.749	-	0.849
Donation	0.002	0.003	-	-	-	-	0.002	-	0.006
Adjusted Profit as per FS	1.288	0.840	1.526	1.996	1.015	0.503	1.009	(0.001)	**8.177**
Allowed Regulatory Return	1.007	1.001	1.004	0.964	0.960	0.680	0.695	0.092	**6.403**
Excess return	**0.282**	**(0.161)**	**0.522**	**1.032**	**0.055**	**(0.176)**	**0.313**	**(0.093)**	**1.774**

DETAILS OF SAVINGS IN O&M EXPENSES

564. O&M expenses allowed as per tariff determination (provided by CPPA-G) exceeded the O&M expenses reported in the financial statements by an amount of Rs.1.37 billion, which has ultimately contributed towards the excess profit of Rs.1.77 billion. The working of comparison of O&M expense incurred and allowed is as follows:

Contribution of Savings in O&M Expenses to Total Excess Profits	
O&M Expenses allowed	Rs.6.78 billion
O&M Expenses incurred	Rs.5.41 billion
Difference in Allowed and Incurred O&M Expenses	Rs.1.37 billion

Details of Savings in O&M Expenses:

Year	Net Delivered Energy	Total Variable O&M	Total Fixed O&M	Total O&M	As per Financials	Difference (Savings)
	Units in Billion	Rs. in Billion				
FY 2010-11	0.178	0.050	0.043	0.093	0.130	(0.037)
FY 2011-12	1.401	0.415	0.439	0.854	0.049	0.805
FY 2012-13	1.380	0.451	0.472	0.923	0.659	0.264
FY 2013-14	1.359	0.477	0.460	0.937	0.831	0.106
FY 2014-15	1.319	0.470	0.481	0.951	0.838	0.113
FY 2015-16	1.231	0.453	0.502	0.955	0.855	0.100
FY 2016-17	1.265	0.478	0.512	0.990	1.214	(0.224)
FY 2017-18	1.392	0.557	0.520	1.077	0.829	0.248
Total FY 2011-2018	**9.526**	**3.351**	**3.429**	**6.780**	**5.407**	**1.373**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.40 billion
Additional Profitability over Remaining Life of Contract	Rs.0.85 billion
Additional Profitability over Life of Project	Rs.1.25 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.15 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
8	**(1.68)**	**1.37**	**2.08**	**0.40**	**0.15**	**-**	**2.32**

Sapphire Electric Company Limited

Background	
Date of Incorporation	January 18, 2005
Ownership Structure	Subsidiary of Sapphire Fibres Limited
Size of Plant	225 MW
Location of Plant	Muridke Sheikhupura
CoD	October 5, 2010
Term of PPA	30 Years

Details of Tariff	
Tariff Petition Submitted on	February 2006
Tariff Petition Admitted on	February 2006
Tariff Petition Granted on	June 2006
Tariff Control Period allowed	30 years
Project Cost allowed	USD 185.552 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*190.01 million*
	Other Costs	*23.87 million*
	Interest During Construction	*10.54 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 15-06-2006**	**COD Determination 21-09-2011**
	Equity	54.922	58.907
	Total debt	130.629	154.060
	Total Project Cost	185.552	212.967
	Debt to Equity Ratio	70.40:29.60	72.34:27.66

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 15-06-2006**	**COD Determination 21-09-2011**
	EPC Cost	143.90	158.85
	Other costs	66.162	69.285
	Interest During Construction (IDC)	14.358	25.715
	Total Project Cost	**185.552**	**212.967**
	Output of the plant	**209 MW**	**212.107MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

565. To determine the profitability and dividend history of SECL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period October 5, 2010 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends 5.10.2010 till 30.6.2018	
Capital Injected by Sponsors	Rs. 4.24 billion
Allowed Regulated Profit	Rs.8.08 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 12.54 billion
Profit after adjustment	Rs. 9.43 billion
Excess Profit	Rs.1.35 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 5.72 billion
Equity Payback after CoD	5 – 6 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

566. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2011 to June 30, 2018 revealed that SECL has earned an Excessive Profit of **Rs.1.35 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion 1.7.2011 till 30.6.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Total**
Adjusted Profit Working									
Accounting Profit Before Tax	2.243	2.379	2.214	2.052	1.035	1.476	0.923	0.212	12.535
Depreciation	0.583	0.584	0.584	0.584	0.577	0.569	0.581	0.446	4.508
Debt Service Cost	(2.090)	(1.976)	(1.979)	(2.162)	(2.003)	(1.899)	(1.966)	(1.55)	(15.62)
Finance Cost Long Term	0.513	0.632	0.796	1.176	1.327	1.491	1.847	1.478	9.260
Cost of WC as CPPA	(0.069)	(0.079)	(0.078)	(0.125)	(0.122)	(0.114)	(0.123)	(0.06)	(0.767)
LPS Energy Purchase Price	(0.229)	(0.114)	(0.155)	(0.122)	(0.135)	(0.263)	(0.314)	(0.04)	(1.375)
LPS Capacity Purchase Price	(0.188)	(0.091)	(0.056)	(0.128)	(0.124)	(0.307)	(0.204)	(0.04)	(1.135)
Finance Cost Short Term	0.250	0.139	0.195	0.355	0.368	0.550	0.551	0.167	2.574
Capitalized Spares	(0.214)	-	-	(0.006)	(0.039)	(0.000)	-	-	(0.260)
Donation	-	-	-	-	-	-	-	0.000	0.000
Other Income	(0.001)	(0.001)	(0.002)	(0.008)	(0.254)	(0.004)	(0.003)	(0.02)	(0.289)
Adjusted Profit	0.798	1.475	1.518	1.615	0.629	1.498	1.292	0.605	**9.430**
Allowed Regulatory Return	1.223	1.167	1.172	1.129	1.066	0.938	0.792	0.588	**8.076**
Excess return	**(0.425)**	**0.307**	**0.345**	**0.486**	**(0.437)**	**0.560**	**0.499**	**0.017**	**1.353**

DETAILS OF SAVINGS IN FUEL COST

567. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.2.29 billion, which has ultimately contributed towards an excess profit of Rs.1.35 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 77.55 billion
Fuel Cost incurred	Rs. 75.26 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 2.29 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2010-11	4.0044	0.818	3.276	3.160	0.116
FY 2011-12	11.2392	0.922	10.359	9.792	0.568
FY 2012-13	13.5549	0.867	11.750	11.850	(0.100)
FY 2013-14	15.8545	0.787	12.483	11.557	0.926
FY 2014-15	13.0102	1.007	13.101	13.706	(0.605)
FY 2015-16	9.7825	0.959	9.382	7.908	1.474
FY 2016-17	8.9797	0.995	8.932	9.083	(0.151)
FY 2017-18	10.1468	0.815	8.269	8.208	0.061
Total FY 2011-2018	**10.8168**	**7.170**	**77.553**	**75.263**	**2.290**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.50 billion
Additional Profitability over Remaining Life of Contract	Rs.1.39 billion
Additional Profitability over Life of Project	Rs.1.89 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.17 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings							
Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
9	2.29	(1.55)	0.61	0.50	0.17	-	2.03

Saif Power Limited

Background	
Date of Incorporation	November 11, 2004
Ownership Structure	Subsidiary of Saif Holdings Limited
Size of Plant	229 MW
Location of Plant	Sahiwal
CoD	April 30, 2010
Term of PPA	30 Years
Details of Tariff	
Tariff Petition Submitted on	June 2006
Tariff Petition Granted on	January 2009
Tariff Control Period allowed	30 years
Project Cost allowed	USD 213.173 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*157.062 million*
	Other Costs	*30.641 million*
	Interest During Construction	*25.47 million*

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 16-01-2009**	**COD Determination 20-06-2011**
	Equity	42.63	55.88
	Total debt	170.54	181.07
	Total Project Cost	213.173	236.950
	Debt to Equity Ratio	80:20	76:24

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**Tariff Determination 16-01-2009**	**COD Determination 20-06-2011**
	EPC Cost	157.062	163.139
	Other costs	30.641	47.2
	Interest During Construction (IDC)	25.47	26.611
	Total Project Cost	**213.173**	**236.950**
	Output of the plant	**208.965MW**	**209.786MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

568. To determine the profitability and dividend history of SPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period April 30, 2010 till December 31, 2018. Details are as follows:

Review of Profitability and Dividends
30.04.2010 till 31.12.2018

Capital Injected by Sponsors	Rs. 3.86 billion
Allowed Regulated Profit	Rs.9.22 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 16.05 billion
Profit after adjustment	Rs. 10.47 billion
Excess Profit	Rs.1.26 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 7.61 billion
Equity Payback after CoD	3 – 4 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

569. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period January 1, 2010 to December 31, 2018 revealed that SPL has earned an Excessive Profit of **Rs.1.26 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.1.2010 till 31.12.2018

Description	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**	**Total**
Adjusted Profit Working										
Accounting Profit Before Tax	3.033	2.592	2.312	2.063	1.988	1.225	1.455	0.779	0.600	16.047
Depreciation	0.594	0.592	0.588	0.588	0.588	0.576	0.577	0.573	0.393	5.069
Debt Service Cost	(2.329)	(2.081)	(2.225)	(2.264)	(2.302)	(2.201)	(2.089)	(2.49)	(1.663)	(19.64)
Finance Cost Long Term	0.590	0.614	0.058	0.988	1.317	1.427	1.754	2.081	1.354	10.184
Cost of WC as CPPA	(0.062)	(0.076)	(0.071)	(0.103)	(0.128)	(0.109)	(0.115)	(0.10)	(0.051)	(0.815)
LPS Energy Purchase Price	(0.296)	(0.171)	(0.101)	(0.140)	(0.180)	(0.237)	(0.414)	(0.20)	-	(1.734)
LPS Capacity Purchase Price	(0.289)	(0.130)	(0.086)	(0.062)	(0.198)	(0.179)	(0.272)	(0.13)	-	(1.346)
Finance Cost Short Term	0.304	0.093	0.033	0.164	0.388	0.408	0.537	0.337	0.092	2.357
Capitalized Spares	-	(0.008)	-	-	-	-	-	(0.08)	-	(0.088)
Donation	0.005	0.002	0.000	-	-	-	-	-	-	0.006
Impairment	-	-	-	-	-	0.611	-	-	-	0.611
Delayed payment charges	-	-	-	-	-	-	0.017	0.003	0.021	0.041
Other Income	(0.002)	(0.004)	(0.013)	(0.028)	(0.059)	(0.053)	(0.025)	(0.03)	(0.003)	(0.218)
Adjusted Profit	1.549	1.422	0.496	1.207	1.414	1.468	1.424	0.747	0.745	**10.472**
Allowed Regulatory Return	1.279	1.084	1.203	1.162	1.084	1.079	0.859	0.869	0.597	**9.216**
Excess return	**0.270**	**0.338**	**(0.707)**	**0.045**	**0.330**	**0.389**	**0.564**	**(0.12)**	**0.148**	**1.256**

DETAILS OF SAVINGS IN FUEL COST

570. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.1.97 billion, which has ultimately contributed towards an excess profit of Rs.1.26 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 79.59 billion
Fuel Cost incurred	Rs. 77.62 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 1.97 billion**

Details of Fuel Savings

Year	**EPP (CPPA)**			**FS IPP**	**Fuel Savings**
	FCC Rate Rs/kWh	**Net Delivered Energy (Units in Billion)**	**FCC Amount**	**Fuel (Raw Material Consumed)**	**Difference (Fuel allowed vs. Consumed)**
			Rs. in Billion		
	(A)	**(B)**	**(C)**	**(D)**	**(E = C-D)**
FY 2009-10	3.2026	0.934	2.991	2.663	0.328
FY 2010-11	7.9654	0.906	7.213	7.254	(0.041)
FY 2011-12	13.4926	0.895	12.080	11.732	0.348
FY 2012-13	11.0621	0.710	7.854	7.243	0.611
FY 2013-14	17.4666	0.757	13.222	13.202	0.021
FY 2014-15	11.9355	0.897	10.712	10.080	0.632
FY 2015-16	6.3743	1.067	6.802	7.238	(0.436)
FY 2016-17	14.3719	0.539	7.751	7.208	0.543
FY 2017-18	9.9240	1.105	10.963	11.000	(0.037)
Total FY 2010-2018	**10.1902**	**7.810**	**79.589**	**77.621**	**1.968**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.58 billion
Additional Profitability over Remaining Life of Contract	Rs.1.34 billion
Additional Profitability over Life of Project	Rs.1.92 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.19 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	**Fuel Cost**	**O&M**	**Un-identified**	**Miscalculation of IRR**	**Mismatch in debt payments**	**Inventory shortfall**	**Total**
	Rs. in Billion						
9	1.97	(0.74)	0.03	0.58	0.19	-	2.02

Orient Power Company (Private) Limited

Background	
Date of Incorporation	June 16, 2003
Ownership Structure	Subsidiary of Oman Oil Company
Size of Plant	229 MW
Location of Plant	Balloki Kasur
CoD	May 24, 2010
Term of PPA	30 Years

Details of Tariff	
Tariff Petition Submitted on	February 2005
Tariff Petition Granted on	September 2009
Tariff Control Period allowed	30 years
Project Cost allowed	USD 168.4 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*147.79 million*
	Other Costs	*20.666 million*

		Tariff Determination 17-09-2009	**COD Determination 13-04-2011**
Capital Structure and Project set-up cost (USD million)	Equity	42.57	61.165
	Total debt	125.83	134.601
	Total Project Cost	168.4	195.766
	Debt to Equity Ratio	75:25	69:31

	Project Costs	**Tariff Determination 17-09-2009**	**COD Determination 13-04-2011**
Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	EPC Cost	147.79	147.79
	Other costs	20.666	47.976
	Total Project Cost	**168.456**	**195.766**
	Output of the plant	**225MW**	**212.70MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

571. To determine the profitability and dividend history of OPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period May 24, 2010 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends
24.05.2010 till 30.6.2018

Capital Injected by Sponsors	Rs. 4.45 billion
Allowed Regulated Profit	Rs.7.87 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 9.85 billion
Profit after adjustment	Rs. 8.93 billion
Excess Profit	Rs.1.07 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 3.12 billion
Equity Payback after CoD	5 – 6 years

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

572. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period July 1, 2010 to June 30, 2018 revealed that OPL has earned an Excessive Profit of **Rs.1.07 billion**. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2010 till 30.6.2018

Description	2018	2017	2016	2015	2014	2013	2012	2011	2010	Total
Adjusted Profit Working										
Accounting Profit Before Tax	1.718	1.621	1.763	1.675	1.134	0.812	0.729	0.406	(0.010)	9.849
Depreciation	0.492	0.542	0.493	0.490	0.486	0.476	0.483	0.481	0.053	3.995
Debt Service Cost	(1.604)	(1.586)	(1.545)	(1.610)	(1.356)	(1.342)	(1.581)	(1.43)	(0.143)	(12.20)
Finance Cost long term	0.388	0.503	0.608	0.903	1.005	1.153	1.483	1.609	0.177	7.829
Cost of WC as CPPA	(0.055)	(0.080)	(0.079)	(0.125)	(0.107)	(0.121)	(0.144)	(0.06)	(0.006)	(0.772)
LPS total	(0.318)	(0.253)	(0.226)	(0.129)	(0.238)	(0.245)	(0.388)	(0.16)	-	(1.954)
Finance Cost short term	0.366	0.261	0.304	0.302	0.331	0.361	0.474	0.350	0.013	2.761
Capitalized Spares (P&M)	(0.002)	(0.007)	(0.029)	(0.018)	(0.285)	(0.010)	(0.033)	(0.07)	-	(0.454)
Donation	-	-	-	-	-	-	-	0.001	-	0.001
Liquidated damages to NTDC	-	-	-	-	-	0.107	-	-	-	0.107
Other Income	(0.060)	(0.029)	(0.016)	(0.017)	(0.018)	(0.017)	(0.016)	(.002)	(0.050)	(0.225)
Adjusted Profit as per FS	0.926	0.972	1.273	1.472	0.951	1.173	1.007	1.129	0.032	**8.935**
Allowed Regulatory Return	1.166	1.173	1.164	1.081	0.929	0.852	0.818	0.611	0.073	**7.867**
Excess return	**(0.24)**	**(0.20)**	**0.110**	**0.391**	**0.021**	**0.321**	**0.189**	**0.518**	**(0.041)**	**1.068**

DETAILS OF SAVINGS IN FUEL COST

573. The fuel cost allowed as per tariff determination (provided by CPPA-G) exceeded the fuel cost reported in the financial statements by an amount of Rs.2.00 billion, which has ultimately contributed towards an excess profit of Rs.1.07 billion, as presented below:

Contribution of Savings in Fuel Cost to Total Excess Profits	
Fuel Cost allowed	Rs. 67.64 billion
Fuel Cost incurred	Rs. 65.64 billion
Difference in Allowed and Incurred Fuel Cost	**Rs. 2.00 billion**
Details of Fuel Savings	

Year	EPP (CPPA)			FS IPP	Fuel Savings
	FCC Rate Rs/kWh	Net Delivered Energy (Units in Billion)	FCC Amount	Fuel (Raw Material Consumed)	Difference (Fuel allowed vs. Consumed)
			Rs. in Billion		
	(A)	(B)	(C)	(D)	(E = C-D)
FY 2009-10	3	0.160	0.433	0.400	0.032
FY 2010-11	4	1.090	4.279	4.011	0.268
FY 2011-12	10	0.682	6.705	6.475	0.230
FY 2012-13	11	0.573	6.501	6.303	0.197
FY 2013-14	14	0.541	7.476	7.161	0.316
FY 2014-15	14	1.037	14.266	14.716	(0.450)
FY 2015-16	9	1.166	10.512	8.533	1.979
FY 2016-17	10	0.945	8.975	9.646	(0.671)
FY 2017-18	10	0.841	8.491	8.395	0.096
Total FY 2010-2018	**84**	**7.036**	**67.637**	**65.641**	**1.997**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.49 billion
Additional Profitability over Remaining Life of Contract	Rs.1.15 billion
Additional Profitability over Life of Project	Rs.1.64 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.12 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	Fuel Cost	O&M	Un-identified	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
	Rs. in Billion						
9	2.00	(1.67)	0.74	0.49	0.124	-	1.68

Halmore Power Generation Company Limited

Background	
Date of Incorporation	March 31, 2005
Size of Plant	225 MW
Location of Plant	Bhikki Sheikhupura
CoD	June 15, 2011
Term of PPA	30 Years
Details of Tariff	
Tariff Petition Submitted on	July 2006
Tariff Petition Granted on	September 2006
Tariff Control Period allowed	30 years
Project Cost allowed	USD 184.382 million
IRR Allowed	USD based equity - 15%

Breakdown of Project Cost allowed (USD)	EPC	*152.163 million*
	Other Costs	*49.258 million*
	Interest during construction	36.240

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 01-09-2006**	**COD Determination 08-01-2014**
	Equity	46.095	51.454
	Total debt	138.287	186.207
	Total Project Cost	184.382	237.661
	Debt to Equity Ratio	75:25	78.35:21.65

Details of EPC, total project cost and changes on account of foreign currency fluctuations (USD million)	**Project Costs**	**COD Determination 08-01-2014**
	EPC Cost	152.163
	Other costs	49.258
	Interest during construction	36.240
	Total Project Cost	**237.661**
	Output of the plant	**212.70MW**

REVIEW OF PROFITABILITY AND DIVIDENDS

574. To determine the profitability and dividend history of HPGCL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period June 15, 2011 till June 30, 2018. Details are as follows:

Review of Profitability and Dividends 15.06.2011 till 30.6.2018	
Capital Injected by Sponsors	Rs. 7.02 billion
Allowed Regulated Profit	Rs.7.80 billion @15% USD equity IRR
Profit Recorded FY2011 to FY2018	Rs. 5.23 billion
Amount withdrawn from Profits as Dividend	Rs. 0.86 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 16% instead of 15%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	16%
Additional Profitability because of Excess IRR Paid (%age)	6.67%
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.49 billion
Additional Profitability over Remaining Life of Contract	Rs.1.60 billion
Additional Profitability over Life of Project	Rs.2.09 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF MISMATCH IN DEBT REPAYMENTS

Mismatch in Debt Repayments	
NEPRA Allowed Debt Repayment Frequency	Quarterly
Actual Debt Repayment Frequency (as per PPA)	Monthly
Benefit because of Mismatch in Payment Frequency	Rs.0.14 billion

SUMMARY OF FINDINGS

Summary of Excess Earnings

Years in Operation Since COD	Fuel Cost	O&M	Un-identified	Miscalculation of IRR	Mismatch in debt payments	Inventory shortfall	Total
	Rs. in Billion						
7	-	-	-	0.49	0.14	-	0.63

COAL BASED THERMAL PLANTS – POWER GENERATION POLICY 2015

Huaneng Shandong Ruyi (Pakistan) Energy (Private) Limited (HSR)

	Background
Date of Incorporation	May 28, 2014
Ownership Structure	Subsidiary of Huaneng Shandong Ruyi (HK) Energy Limited, which is 50% owned by Huaneng Shandong Power Generation Company Limited and 50% by Shandong Ruyi Science and Technology Group Company Limited.
Type of Plant	Coal- fired
Size of Plant	Gross Capacity: 1,320 MW Net Capacity: 1,243.52 MW
Location of Plant	Qadirabad, District Sahiwal
CoD	October 28, 2017

TARIFF DETAILS

575. HSR requested an unconditional acceptance of NEPRA's upfront tariff for 2x660 MW Coal Power Plant, which was approved by NEPRA[76] on March 31, 2015, with the following cost assumption for the project:

	For 660MW USD million	For 1,320 MW USD million
CAPEX without customs duties	767.868	1,535.74
Customs Duty & Cess	30.497	60.99
CAPEX	**798.365**	**1,596.73**
Financial Charges		
Financing Fees & Charges	20.957	41.91
Sinosure Fee	63.940	127.88
Interest During Construction (IDC)	72.797	145.59
Sub total	**157.694**	**315.39**
Total Project Cost	**956.059**	**1,912.12**

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[76] NEPRA/TRF-308/HSRPEL-2015/4385-4387

576. As per the tariff documents, IDC will be re-established at the time of CoD based on:

i. Indexed capital cost (as per the formula given in the Upfront Coal Tariff 2014);

ii. Actual custom duties & cess;

iii. Withholding tax on contracts/services;

iv. Actual premium on LIBOR & KIBOR subject to maximum of 4.5% and 3.5%, respectively; and

v. The impact of Sinosure fee, if any.

REVIEW OF TARIFF ADJUSTMENT AT COMMERCIAL OPERATION DATE (COD)

577. After CoD, HSR submitted a request for adjustment of relevant components of tariff at CoD[77] on March 20, 2018. Subsequently, they submitted a revised request on May 9, 2018[78], and on January 17, 2019, NEPRA gave a determination on the tariff adjustment at CoD of HSR[79].

578. HSR had requested an IDC of USD 197.33 million at CoD on the basis of the following calculation:

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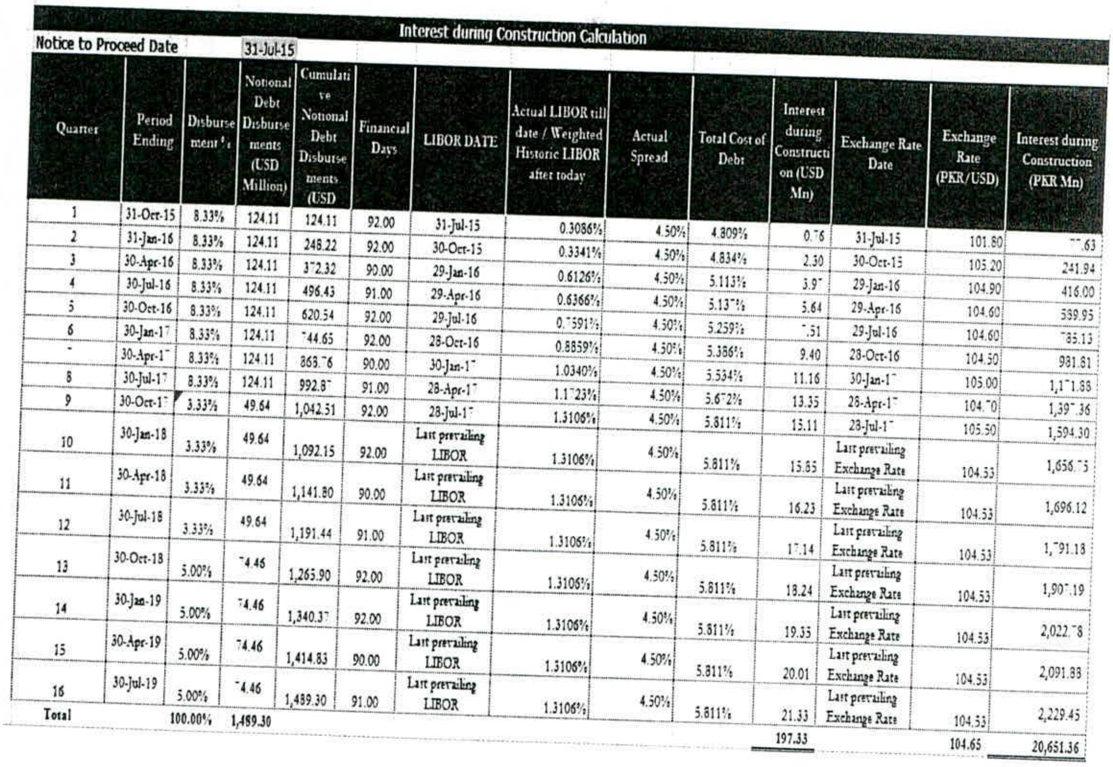
[77] HSR-SWLCOMMERCIAL-359

[78] HSRSWL-COMMERCIAL-86

[79] NEPRA/TRF-308/HSRPEL-2015/715-717



Interest during Construction Calculation

Notice to Proceed Date 31-Jul-15

Quarter	Period Ending	Disbursement %	Notional Debt Disbursements (USD Million)	Cumulative Notional Debt Disbursements (USD	Financial Days	LIBOR DATE	Actual LIBOR till date / Weighted Historic LIBOR after today	Actual Spread	Total Cost of Debt	Interest during Construction (USD Mn)	Exchange Rate Date	Exchange Rate (PKR/USD)	Interest during Construction (PKR Mn)
1	31-Oct-15	8.33%	124.11	124.11	92.00	31-Jul-15	0.3086%	4.50%	4.809%	0.76	31-Jul-15	101.80	77.63
2	31-Jan-16	8.33%	124.11	248.22	92.00	30-Oct-15	0.3341%	4.50%	4.834%	2.30	30-Oct-15	105.20	241.94
3	30-Apr-16	8.33%	124.11	372.32	90.00	29-Jan-16	0.6126%	4.50%	5.113%	3.97	29-Jan-16	104.90	416.00
4	30-Jul-16	8.33%	124.11	496.43	91.00	29-Apr-16	0.6366%	4.50%	5.137%	5.64	29-Apr-16	104.60	589.95
5	30-Oct-16	8.33%	124.11	620.54	92.00	29-Jul-16	0.7591%	4.50%	5.259%	7.51	29-Jul-16	104.60	785.13
6	30-Jan-17	8.33%	124.11	744.65	92.00	28-Oct-16	0.8859%	4.50%	5.386%	9.40	28-Oct-16	104.50	981.81
7	30-Apr-17	8.33%	124.11	868.76	90.00	30-Jan-17	1.0340%	4.50%	5.534%	11.16	30-Jan-17	105.00	1,171.88
8	30-Jul-17	8.33%	124.11	992.87	91.00	28-Apr-17	1.1723%	4.50%	5.672%	13.35	28-Apr-17	104.70	1,397.36
9	30-Oct-17	3.33%	49.64	1,042.51	92.00	28-Jul-17	1.3106%	4.50%	5.811%	15.11	28-Jul-17	105.50	1,594.30
10	30-Jan-18	3.33%	49.64	1,092.15	92.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	15.85	Last prevailing Exchange Rate	104.53	1,656.75
11	30-Apr-18	3.33%	49.64	1,141.80	90.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	16.23	Last prevailing Exchange Rate	104.53	1,696.12
12	30-Jul-18	3.33%	49.64	1,191.44	91.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	17.14	Last prevailing Exchange Rate	104.53	1,791.18
13	30-Oct-18	5.00%	74.46	1,265.90	92.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	18.24	Last prevailing Exchange Rate	104.53	1,907.19
14	30-Jan-19	5.00%	74.46	1,340.37	92.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	19.35	Last prevailing Exchange Rate	104.53	2,022.78
15	30-Apr-19	5.00%	74.46	1,414.83	90.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	20.01	Last prevailing Exchange Rate	104.53	2,091.88
16	30-Jul-19	5.00%	74.46	1,489.30	91.00	Last prevailing LIBOR	1.3106%	4.50%	5.811%	21.33	Last prevailing Exchange Rate	104.53	2,229.45
Total		100.00%	1,489.30							197.33		104.65	20,651.36

579. Against HSR's request, NEPRA allowed US $ 167.912 million (Rs. 17,562.588 million) as IDC at CoD. After incorporating the increased IDC as well as other adjustments[80], the following project cost was allowed to HSR:

	For 660MW USD million	For 1320 MW USD million
CAPEX without customs duties	**660.88**	**1,321.75**
Customs Duty & Cess	76.08	152.16
CAPEX	**736.95**	**1,473.91**
Financial Charges		
Financing Fees & Charges	20.56	41.12
Sinosure Fee	49.69	99.37
Interest During Construction (IDC)	83.96	167.91
Sub total	**154.20**	**308.40**
Total Project Cost	**891.16**	**1,782.31**

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[80] Including a downward revision of CAPEX on account of application of Capex adjustment formula and Chinese Boiler instead of European Boiler

COMPARISON OF FINANCIAL STATEMENTS OF HSR WITH TARIFF

580. Note 13.1 of the financial statements of HSR for the year ended December 31, 2017 (CoD year) reports an operational fixed asset carried at net book value of Rs. 172.19 billion, which translates into a cost of **Rs. 173.25 billion** after adding back relevant accumulated depreciation of Rs. 1.06 billion.

581. The relevant extract of financial statements for the years 2015, 2016 and 2017 is given below:

As of December, 31	**2015**	**2016**	**2017**
Property Plant and Equipment	33,109,404	71,022,000	172,192,228,000
Capital Work in Progress	18,861,534,363	101,885,535,000	
Total	**18,894,643,767**	**101,956,557,000**	**172,192,228,000**
Financed by:			
Share capital	21,424,418,000	27,918,348,000	37,564,776,000
Borrowing	-	69,945,017,000	136,433,023,000
Total	**21,424,418,000**	**97,863,365,000**	**173,997,799,000**

582. It is pertinent to note the following:

	USD	RS. (@104.59)
Project Cost allowed by NEPRA	1,782.312 million	186.41 billion
Project cost reported in Financial Statements	Rs. 173.25 billion	
Excess project cost allowed (Allowed - Reported)	**Rs. 13.16 billion**	

583. An in-depth review of the causes of excess allowance of Rs. 13.16 billion in setup costs revealed :

For the year ended Dec 31, 2015:

Only equity was injected to finance the project and there was no borrowing. Therefore, there was no interest cost during this time period (relevance of this is explained later in this analysis)

For the year ended Dec 31, 2016:

Rs. 69,945,017,000 was borrowed during the year, details of which are tabulated below:

Bank	Facility available	Rate per annum	Draw down (USD)	In RS.	Repayment terms
	million				
ICBC-Beijing Branch	70	3m Libor + 1.15%	68	7,112.7	1 year from draw down
ICBC - Shandong branch	200	6m Libor + 0.6%	200	20,919.7	6 months from draw down
China Construction Bank Corporation – Seoul	203.7	1.45%	203.7	21,306.7	6 months from draw down
Bank of China Limited	99	3m Libor + 0.8%	99	10,355.3	1 year from draw down
Industrial and Commercial Bank of China (Macau)	100	1.60%	98	10,250.7	For working capital 1 year from draw down
Total			**668.7**	**69,945**	

Further, note 12.2.2.2 of the financial statements for the year ended Dec 31, 2016 revealed that the markup on these short terms loans for the year aggregated to **Rs. 482,861,000.**

For the year ended Dec 31, 2017:

Rs. 155,929,000,000 was borrowed during the year from a consortium of banks as per the following details:

Bank	Facility Million USD	Rate per annum	Draw down Million USD	Reported in Million RS.	Repayment terms
ICBC	1,440	3m Libor + 4.5%	1,411	155,929	Forty-eight unequal quarterly installments
Agriculture Bank of China Ltd. (Shandong)					
China Construction Bank (Shandong)					
Bank of China (Jinan)					

HSR achieved its CoD on October 28, 2017, and a review of note 13.2.2.2 of the financial statements revealed that HSR incurred markup of:

- *Rs. 328,139,000 on the short-term loans obtained during the year ended Dec 31, 2016; and*
- *Rs. 5,897,477,000 on the long-term loan obtained during the year ended Dec 31, 2017.*

584. A comparison of the markup amounts reported in the financial statements with those allowed by NEPRA in CoD tariff adjustments revealed that IDC overpayment has contributed to 80% of the total overpayment amount of Rs. 13.17 billion overpaid on account of setup cost. Details are as follows:

	USD	RS. (@104.59)
IDC sought by HSR	USD 197.34 million	-
IDC allowed by NEPRA	USD 167.91 million	Rs. 17.56 billion
IDC reported in Financial Statements	-	Rs. 6.71 billion
Excess IDC allowed (Allowed - Reported)	**USD 103.77 million**	**Rs. 10.85 billion**

NOTE: The remaining amount of Rs. 2.3 billion is to be further investigated since the requisite information was not available at the time of submission of this report.

585. HSR claimed IDC based on markup on long term loan @ LIBOR + 4.5% during the entire construction period, whereas, the financial statements of the Company revealed that the Company did not borrow any funds during the first year of construction and obtained short term loans at substantially lower interest rates during the second year of construction. Apparently therefore, there is an element of misrepresentation by the sponsors of the IPP.

586. HSR didn't share complete information with NEPRA for adjustment of the IDC component of project cost. During the construction period, the spread over LIBOR actually ranged from 0.6% to 1.6%, whereas the Company claimed interest during construction at LIBOR + 4.5% flat spread.

587. Para 56 xii (b)(D) of the Upfront Tariff 2014 mandates that any reduction in spread is to be shared between the Power Purchaser and Power Producer in a ratio of 60:40. Such reduction would have decreased the IDC resulting in reduction of tariff at COD.

FINDING-2: EXCESS RETURN PAYMENT OF USD 27.40 MILLION PER ANNUM

588. At the time of COD tariff determination, NEPRA allowed a project cost of USD 1.78 billion and USD 0.36 billion in equity. However, after adjusting for overpayments in

setup cost (mainly IDC) as explained in previous paragraphs, the adjusted project cost and equity work out to be USD 1.68 billion and USD 0.34 billion, respectively.

589. Based on this adjusted equity amount, HSR was entitled to a return of USD 70.90 million per year. However, HSR has been allowed USD 98.30 million, resulting in an excess of USD 27.40 million in annual return payments as elaborated in the table below:

Figures in USD millions except where otherwise mentioned			
	Allowed by NEPRA	**Adjusted for overpayment**	**Difference**
Project Cost	1,782.31	1,678.54	103.77
Equity (20.3%)	361.62	340.57	21.05
ROE	27.18%	20.82%	
Annual Payments (Equity x ROE)	98.30	70.90	27.40
Exchange rate (USD/PKR)	155	155	
Payments over 30 years in RS.	457,088	329,689	127,400

590. Given the reference exchange rate of RS. 155 per USD, and assuming that USD appreciates against PKR at an average rate of 6% per annum (actual yearly depreciation was around 6.87% during last 9 years), the excess payment works out to be **RS. 291.04 billion** over the tariff control period of 30 years.

Port Qasim Electric Power Company (Private) Limited(PQE)

Background	
Date of Incorporation	August 12, 2014
Ownership Structure	Wholly-owned subsidiary of Port Qasim Energy Dubai (Holding) Limited, which is 51% held by Port Qasim Energy (Hong Kong) Holding Limited and 49% by Al-Mirqab Capital S.P.C. Qatar holds 49% of the shares.
Type of Plant	Coal-fire pure condensation power units
Size of Plant	2 x 660 MW
Location of Plant	Port Qasim, Karachi
CoD	April 25, 2018

TARIFF APPROVAL

591. PQE requested an unconditional acceptance of NEPRA's upfront tariff for 2 x 660 MW Coal Power Plant, which was approved by NEPRA[81] on February 13, 2015, with the following cost assumption for the project:

	For 660MW	**For 1320 MW**
	USD million	
Capital Cost	**767.9**	**1,535.8**
Customs Duty & Cess	30.5	60.99
Sub-total	**798.4**	**1,596.8**
Financial Charges		
Financing Fees & Charges	21.0	42.0
Sinosure Fee	63.9	127.8
Interest During Construction (IDC)	72.8	145.6
Sub-total	**157.7**	**315.4**
Total Project Cost	**956.1**	**1,912.2**

592. As per the tariff document, IDC was to be re-established at the time of CoD based on:

i. Indexed capital cost;

ii. Actual custom duties & cess;

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[81] NEPRA/TRF-299/PQEPCPL-2015/1839-1841

iii. Withholding tax on contracts/services;

iv. actual premium on LIBOR & KIBOR subject to maximum of 4.5% and 3.5% respectively; and

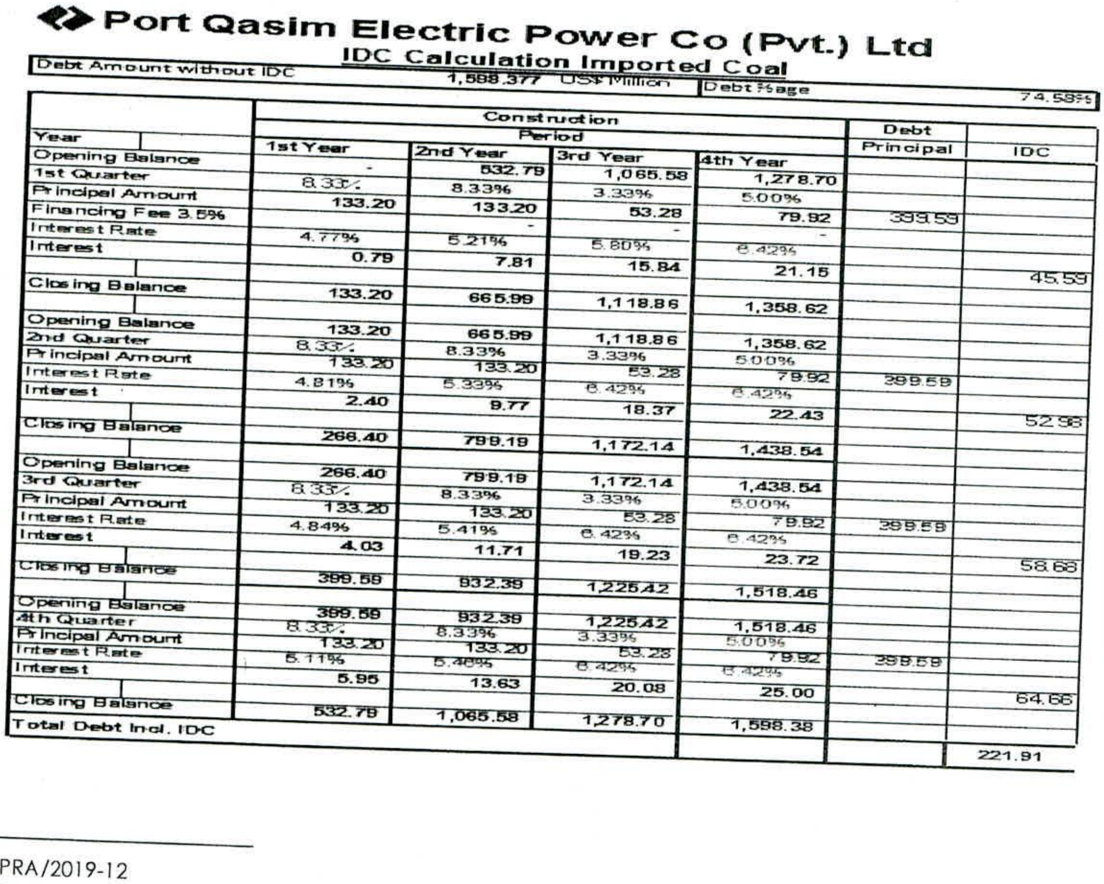
v. The impact of Sinosure fee, if any.

593. Capital cost was also to be adjusted as per the formula given in the Upfront Coal Tariff 2014.

REVIEW OF TARIFF ADJUSTMENT AT COMMERCIAL OPERATION DATE (COD)

594. After CoD, PQE submitted its request for adjustment of relevant components of its tariff on April 8, 2019[82]. On September 27, 2019, NEPRA gave its determination[83] on the tariff adjustment request.

595. PQE had requested an IDC of USD 221.907 million at CoD on the basis of the following calculation:



Port Qasim Electric Power Co (Pvt.) Ltd

IDC Calculation Imported Coal

Debt Amount without IDC | 1,598.377 US$ Million | Debt %age | 74.59%

Year	Construction Period 1st Year	2nd Year	3rd Year	4th Year	Debt Principal	IDC
Opening Balance	-	532.79	1,065.58	1,278.70		
1st Quarter	8.33%	8.33%	3.33%	5.00%		
Principal Amount	133.20	133.20	53.28	79.92	399.59	
Financing Fee 3.5%		-	-	-		
Interest Rate	4.77%	5.21%	5.80%	6.42%		
Interest	0.79	7.81	15.84	21.15		45.59
Closing Balance	133.20	665.99	1,118.86	1,358.62		
Opening Balance	133.20	665.99	1,118.86	1,358.62		
2nd Quarter	8.33%	8.33%	3.33%	5.00%		
Principal Amount	133.20	133.20	53.28	79.92	399.59	
Interest Rate	4.81%	5.33%	6.42%	6.42%		
Interest	2.40	9.77	18.37	22.43		52.98
Closing Balance	266.40	799.19	1,172.14	1,438.54		
Opening Balance	266.40	799.19	1,172.14	1,438.54		
3rd Quarter	8.33%	8.33%	3.33%	5.00%		
Principal Amount	133.20	133.20	53.28	79.92	399.59	
Interest Rate	4.84%	5.41%	6.42%	6.42%		
Interest	4.03	11.71	19.23	23.72		58.68
Closing Balance	399.59	932.39	1,225.42	1,518.46		
Opening Balance	399.59	932.39	1,225.42	1,518.46		
4th Quarter	8.33%	8.33%	3.33%	5.00%		
Principal Amount	133.20	133.20	53.28	79.92	399.59	
Interest Rate	5.11%	5.46%	6.42%	6.42%		
Interest	5.95	13.63	20.08	25.00		64.66
Closing Balance	532.79	1,065.58	1,278.70	1,598.38		
Total Debt Incl. IDC						221.91

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[82] PQEPC/NEPRA/2019-12

[83] NEPRA/R/TRF-299/PQEPCPL-2015/17908-17910

596. Against PQE's request, NEPRA allowed the following IDC at CoD:

   i. US $ 152.56 million (Rs. 16,130.169 million) for plant

   ii. US $ 11.18 million (Rs. 1,182.061 million) for jetty

597. After incorporation of increased IDC as well as other adjustments, the following project cost was allowed to the Company:

	For 660MW USD million	**For 1320 MW** USD million
Capital Cost Power Plant	729.76	1,459.511
Customs Duties & Cess	30.20	60.394
EPC Cost Power Jetty	113.05	226.1
Customs Duties & Cess - Jetty	0.80	1.6
Sub-total	**873.81**	**1,747.605**
Financial Charges		
Financing Fees & Charges	23.99	47.979
Sinosure Fee	11.60	23.194
Interest During Construction (IDC) - Plant	76.28	152.56
Interest During Construction (IDC) - Jetty	5.59	11.180
Sub-total	**117.46**	**234.913**
Total Project Cost	**991.26**	**1,982.518**

COMPARISON OF FINANCIAL STATEMENTS OF PQE AND WITH TARIFF

598. Note 5.1 of the financial statements of PQE for the year ended Dec 31, 2018 reports operating fixed assets carried at net book value of USD 1,760.52 million which translates into cost of **USD 1,799.986 million** after adding back relevant accumulated depreciation of USD 39.468 million.

599. The relevant extract of financial statements for the years 2015, 2016, 2017 and 2018 is given below:

As at	30.6.2015	30.6.2016	31.12.2016	31.12.2017	31.12.2018
			Rupees		
Property Plant and Equipment	711,000	136,937,000	125,363,000	94,109,000	235,069,896,000
Capital Work in Progress	702,788,000	44,942,214,000	116,231,729,000	177,682,051,000	-
Advances to suppliers	11,876,000	16,851,148,000	5,492,023,000	3,331,612,000	3,350,517,000
Capital spares					5,587,659,000
	715,375,000	**61,930,299,000**	**121,849,115,000**	**181,107,772,000**	**244,008,072,000**
Cash and bank balance	126,774,000	6,915,079,000	11 ,309,980,000	3,031,154,000	23,724,855,000
Financed by:					
Share capital	497,074,000	23,022,281,000	31,969,155,000	48,420,880,000	73,723,000,000
Borrowing	-	43,974,000,000	93,796,000,000	129,616,500,000	216,300,500,000
Total	**497,074,000**	**66,996,281,000**	**125,765,155,000**	**178,037,380,000**	**290,023,500,000**

600. It is pertinent to note:

Project Cost allowed by NEPRA	USD 1,982.518 million
Project cost reported in Financial Statements	USD 1,799.986
Excess project cost allowed (Allowed - Reported)	**USD 182.532 million**

601. An in-depth review of the causes of excess allowance of USD 182.532 million in setup costs revealed

For the year ended June 30, 2015

Only equity aggregating to Rs. 497.074 million was injected to finance the project and there was no borrowing. Therefore, there was no interest cost during this time period.

For the year ended June 30, 2016

- *Long term borrowing of USD 1,555,000,000 was negotiated with The Export-Import Bank of China @ 6 months LIBOR plus 3.7%; and*
- *USD 420,000,000 were drawn during the year.*

Note 3.2 of the financial statements showed the markup on this borrowing for the year ended June 30 2016 aggregated to USD 29,220,000 (Rs. 3,053,490,000).

For the half year ended Dec 31, 2016

USD 475,000,000 were drawn resulting in the total borrowing rising to USD 895,000,000. Note 3.2 of the financial statements showed that the markup on this borrowing for the half-year ended Dec 31, 2016 aggregated to USD 19,342,000 (Rs. 2,026,095,000).

For the year ended Dec 31, 2017

USD 278,000,000 were drawn resulting in total borrowing of USD 1,173,000,000. Note 3.2 of the financial statements showed the markup on this borrowing for the year ended Dec 31, 2017 aggregated to USD 57,433,000 (Rs. 6,611,664,000).

For the year ended Dec 31, 2018

USD 382,000,000 were drawn resulting in total borrowing of USD 1,555,000,000 (total negotiated amount). Note 3.2 of the financial statements showed that the markup on this borrowing for the period ended April 24, 2018 (CoD) aggregated to USD 6,793,000 (Rs. 835,275,000).

Further, as per CoD determination, PQE was allowed an equity of Rs. 45.19 billion, against which PQE had already injected equity of Rs. 73.72 billion leading to an excess equity of **Rs. 28.53 billion** which was in fact not required for the project and is mainly reflected in cash and bank balance of Rs. 23.72 billion at the year end.

602. A comparison of the markup amounts reported in the financial statements with those allowed by NEPRA in CoD tariff adjustments revealed that the financing cost overpayment has contributed to two-third of the total amount of USD 182.532 million (Rs19.3 billion) overpaid on account of setup cost. Details are as follows:

	USD	RS.
Financing Cost sought by PQE		
Financing Cost allowed by NEPRA	234.913 million	24.84 billion
Financing Cost reported in Financial Statements	112.788 million	12.53 billion
Excess Financing Cost allowed (Allowed - Reported)	**122.125 million**	**12.31 billion**

NOTE: The remaining one third excess financing cost is to be further investigated since the requisite information was not available at the time of submission of this report.

603. Unlike in the case of HSR, in the case of PQE, NEPRA corrected the error of the construction period and assumed actual construction period to compute return during the construction period.

Foundation Wind Energy-II Limited (FWEL-II)

Background	
Formerly	Green Power (Pvt.) Limited (GPL)
Ownership Structure	Fauji Fertilizer
Size of Plant	50 MW
Location of Plant	Gharo, District Thatta, Sindh Province
CoD	December 10, 2014
Details of Tariff	
Original Tariff for GPL granted on	April 27, 2007
Tariff Petition Re-Submitted on	September 9, 2011
Tariff Petition Admitted on	September 14, 2011
Tariff Granted to FWEL-II on	March 16, 2012
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 124.907 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Biannual basis
Tariff Adjustment after CoD Allowed on	June 9, 2016

Capital Structure and Project set-up cost (USD million)		**Determination 16-03-2012**	**COD Determination 09-06-2016**
	Equity	*31.227*	*34.580*
	Total debt	*93.680*	*88.919*
	Total Project Cost	***124.907***	***123.499***
	Debt to Equity Ratio	*75:25*	*72:28*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 16-03-2012**	**COD Determination 09-06-2016**
	EPC Cost	***111.023***	***108.663***
	Non-EPC costs	*1.000*	*0.820*
	Project development costs	*2.750*	*2.929*
	Duties and taxes	*0.716*	*0.740*
	Pre-COD insurance	*1.499*	*1.029*
	Financial charges	*2.632*	*2.466*
	Interest during construction	*5.287*	*6.849*
	Total Project Cost	***124.907***	***123.497***

REVIEW OF PROFITABILITY AND DIVIDENDS

604. To determine the profitability and dividend history of FWEL-II, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant

publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends 01.7.2014 till 30.6.2019	
Capital Injected by Sponsors	Rs.3.528 billion
Allowed Regulated Profit	Rs.3.60 billion
Profit Recorded FY 2015 to FY 2019	Rs.4.13 billion
Profit after adjustment	Rs.3.74 billion
Excess Profit	Rs. 0.14 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs. 0.35 billion

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

605. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period 2015 to 2019 revealed that FWEL-II has earned an Excessive Profit of Rs.0.14 billion. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion 1.7.2014 till 30.6.2019						
Description	**2019**	**2018**	**2017**	**2016**	**2015**	**Total**
Accounting Profit/(Loss) Before tax	1.228	0.943	0.834	1.178	(0.059)	4.125
Depreciation	0.668	0.623	0.623	0.615	0.343	2.873
Finance Cost Long term	0.632	0.507	0.509	0.555	0.368	2.572
Debt Service Cost	(1.421)	(1.271)	1.222)	(1.385)	(0.560)	(5.859)
Finance Cost Short Term	0.003	0.004	0.029	0.076	0.002	0.114
Donation	0.002	0.002	0.0008	-	-	0.005
Other Income	(0.056)	(0.012)	(0.018)	0.003	(0.006)	(0.089)
Adjusted Profit	**1.057**	**0.796**	**0.757**	**1.042**	**0.088**	**3.740**
Allowed Regulatory Return	0.953	0.777	0.731	0.829	0.314	**3.604**
Excess return	0.104	0.019	0.026	0.213	(0.227)	0.135

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.27 billion
Additional Profitability over Remaining Life of Contract	Rs.0.82 billion
Additional Profitability over Life of Project	Rs.1.09 billion

Sapphire Wind Power Company Limited (SWPCL)

Background		
Ownership Structure		Sapphire Group
Size of Plant		49.50 MW
Upgrade the Size of Plant on Nov 19, 2014		52.80 MW
Location of Plant		Jhimpir, District Thatta, Sindh Province
Details of Tariff		
Original Tariff for SWPCL granted on		April 27, 2007
Tariff Petition Submitted on		September 12, 2011
Tariff Petition Admitted on		September 14, 2011
Tariff (Cost plus) Granted to SWPCL on		May 8, 2012
Tariff (Upfront) Granted to SWPCL on		November 21, 2013
Tariff Control Period sought		20 years
EPC Project		Turney basis – no detail of equipment provided
Project Cost allowed		USD 128.872 million
IRR Allowed		17% for a period of 20 years
Debt Repayment Period allowed		10 years with repayment schedule on a Biannual basis
Capital Structure and Project set-up cost (USD million)		**Determination - 08-05-2012**
	Equity	*32.218*
	Total debt	*96.654*
	Total Project Cost	***128.872***
	Debt to Equity Ratio	*75:25*
Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination - 08-05-2012**
	EPC Cost	*107.500*
	Letter of credit confirmation charges	*1.095*
	Non-EPC costs	*1.348*
	Project development costs	*2.891*
	Land cost	*0.119*
	Duties and taxes	*0.719*
	Pre-COD insurance	*1.466*
	Financial charges	*3.602*
	Sinosure fee	*4.635*
	Working capital	*0.992*
	Interest during construction	*4.505*
	Total Project Cost	***128.872***

REVIEW OF PROFITABILITY AND DIVIDENDS

606. To determine the profitability and dividend history of SEPCL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends *1.7.2015 till 30.6.2019*	
Capital Injected by Sponsors	Rs.3.26 billion
Allowed Regulated Profit	Rs.2.68 billion
Profit Recorded FY 2016 to FY 2019	Rs.3.74 billion
Profit after adjustment	Rs.2.74 billion
Excess Profit	Rs.0.056 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.73 billion

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

607. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period 2016 to 2019 revealed that SWPCL has earned an Excessive Profit of Rs.0.056 billion. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2015 till 30.6.2019

Description	**2019**	**2018**	**2017**	**2016**	**Total**
Accounting Profit / (Loss) Before tax	1.291	0.963	0.809	0.679	3.743
Depreciation	0.654	0.596	0.587	0.386	2.223
Debt Service Cost	-1.690	-1.369	-1.275	-0.897	-5.232
Finance Cost Long term	0.631	0.487	0.456	0.268	1.841
Finance Cost Short Term	0.061	0.050	0.057	0.036	0.204
Capitalized Spares (P&M)	0.000	0.000	0.000	0.000	0.000
Donation	0.004	0.004	0.002	0.000	0.010
Other Income	-0.029	-0.012	-0.007	-0.001	-0.049
Adjusted Profit	**0.923**	**0.719**	**0.628**	**0.470**	**2.740**
ved Regulatory Return	**0.829**	**0.694**	**0.675**	**0.486**	**2.684**
ss return	**0.094**	**0.025**	**-0.047**	**-0.016**	**0.056**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.21 billion
Additional Profitability over Remaining Life of Contract	Rs.0.86 billion
Additional Profitability over Life of Project	Rs.1.07 billion

Zorlu Enerji Pakistan Limited (ZEPL)

Background	
Size of Plant	49.50 MW
Upgrade the Size of Plant on May 2008	50 MW
Upgrade the Size of Plant on July 2011	56.40 MW
Location of Plant	Jhimpir, near Nooriabad, District Thatta, Sindh Province
CoD	July 26, 2013
Details of Tariff	
Original Tariff for ZEPL granted on	December 18, 2007
Tariff Petition Re-Submitted on	May 23, 2008
Tariff Petition Re-Submitted on	July 19, 2011
Tariff Petition Admitted on	September 14, 2011
Tariff Granted to ZEPL on	December 18, 2007 & July 19, 2011
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 108.942 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Quarterly basis
Tariff Adjustment after CoD Allowed on	February 20, 2015

Capital Structure and Project set-up cost (USD million)		**Determination 18-12-2007**	**COD Determination 20-02-2015**
	Equity	*21.788*	*39.103*
	Total debt	*87.154*	*91.239*
	Total Project Cost	***108.942***	***130.342***
	Debt to Equity Ratio	*80:20*	*70:30*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 18-12-2007**	**COD Determination 20-02-2015**
	EPC Cost	***102.212***	***117.394***
	Non-EPC costs	*1.692*	*4.588*
	Project development costs	*0.081*	-
	Duties and taxes	*0.415*	*0.973*
	Pre-COD insurance	*0.965*	*2.582*
	Financial charges	*3.577*	*4.805*
	Total Project Cost	***108.942***	***130.342***

REVIEW OF PROFITABILITY AND DIVIDENDS

608. To determine the profitability and dividend history of ZEPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends ***1.1.2013 till 31.12.2018***	
Capital Injected by Sponsors	Rs.2.921 billion
Allowed Regulated Profit	Rs.4.62 billion
Profit Recorded FY 2013 to FY 2018	Rs.3.47 billion
Profit after adjustment	Rs.3.43 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.00 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.35 billion
Additional Profitability over Remaining Life of Contract	Rs.0.82 billion
Additional Profitability over Life of Project	Rs.1.17 billion

Three Gorges First Wind Farm Pakistan (Pvt.) Limited

Background	
Size of Plant	49.50 MW
Location of Plant	Jhimpir, near Nooriabad, District Thatta, Sindh Province
CoD	November 25, 2014
Details of Tariff	
Original Tariff for Three Gorges-I granted on	December 15, 2011
Tariff Petition Submitted on	June 9, 2011
Tariff Petition Admitted on	June 24, 2011
Tariff (Cost Plus) Granted to Three Gorges-I on	December 15, 2011
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 130.279 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Biannual basis
Tariff Adjustment after CoD Allowed on	January 22, 2016 & October 28, 2016

Capital Structure and Project set-up cost (USD million)		**Determination 15-12-2011**	**COD Determination 28-10-2016**
	Equity	*26.056*	*25.823*
	Total debt	*104.223*	*103.292*
	Total Project Cost	***130.279***	***129.115***
	Debt to Equity Ratio	*80:20*	*80:20*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 15-12-2011**	**COD Determination 28-10-2016**
	EPC Cost	*110.315*	*109.998*
	Non-EPC costs	*1.10*	*1.10*
	Project development costs	*2.93*	*2.93*
	Duties and taxes	*0.419*	*1.019*
	Pre-COD insurance	*1.489*	*0.800*
	Financial charges	*2.79*	*2.780*
	Sinosure fee	*6.806*	*6.745*
	Interest during construction	*4.43*	*3.742*
	Total Project Cost	***130.279***	***129.114***

REVIEW OF PROFITABILITY AND DIVIDENDS

609. To determine the profitability and dividend history of Three Gorges – I, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends ***1.1.2014 till 31.12.2018***	
Capital Injected by Sponsors	Rs.2.555 billion
Allowed Regulated Profit	Rs.2.48 billion
Profit Recorded FY 2014 to FY 2018	Rs.3.59 billion
Profit after adjustment	Rs.2.49 billion
Excess Profit	Rs.0.014 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.00 billion

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

610. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period 2014 to 2018 revealed that Three Gorges – I has earned an Excessive Profit of Rs.0.014 billion. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.1.2014 till 31.12.2018

Description	**2019**	**2018**	**2017**	**2016**	**2015**	**Total**
Accounting Profit / (Loss) Before tax	1.126	1.015	1.161	0.341	-0.052	3.591
Depreciation	0.791	0.672	0.580	0.726	0.057	2.827
Debt Service Cost	-1.762	-1.587	-1.559	-1.537	-0.069	-6.515
Finance Cost Long Term	0.692	0.605	0.632	0.639	0.068	2.636
Finance Cost Short Term	0.000	0.000	0.000	0.010	0.001	0.010
Other Income	-0.015	-0.017	-0.012	-0.010	-0.001	-0.055
Adjusted Profit	0.833	0.689	0.801	0.169	0.003	2.495
Allowed Regulatory Return	0.665	0.597	0.594	0.598	0.027	2.481
Excess return	0.168	0.091	0.207	-0.429	-0.024	0.014

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.19 billion
Additional Profitability over Remaining Life of Contract	Rs.0.56 billion
Additional Profitability over Life of Project	Rs.0.75 billion

FFC Energy Limited (FFCEL)

Background	
Ownership Structure	Fauji Fertilizer Company Limited
Size of Plant	49.50 MW
Location of Plant	Jhimpir, District Thatta, Sindh Province
CoD	May 16, 2013
Details of Tariff	
Original Tariff for FFCEL granted on	August 10, 2010
Tariff Petition Submitted on	April 7, 2010
Tariff Petition Admitted on	April 15, 2010
Tariff (Cost Plus) Granted to FFCEL on	August 10, 2010
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 133.557 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Biannual basis
Tariff Adjustment after CoD Allowed on	November 10, 2014

		Determination 10-08-2010	**COD Determination 10-11-2014**
Capital Structure and Project set-up cost (USD million)	Equity	*26.711*	*26.700*
	Total debt	*106.846*	*106.802*
	Total Project Cost	***133.557***	***133.501***
	Debt to Equity Ratio	*80:20*	*80:20*

	Project Costs	**Tariff Determination 10-08-2010**	**COD Determination 10-11-2014**
Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**EPC Cost**	**111.199**	**111.199**
	LC Opening Charges	1.250	0.355
	Duty and taxed	0.693	0.558
	Non-EPC Cost	3.873	3.556
	Project development costs		
	Pre-COD Insurance	1.518	1.350
	Financial Charges	3.102	2.808
	Interest During Construction	11.922	13.675
	Total Project Cost	***133.557***	***133.501***

REVIEW OF PROFITABILITY AND DIVIDENDS

611. To determine the profitability and dividend history of FFCEL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends *1.1.2013 till 31.12.2018*	
Capital Injected by Sponsors	Rs.2.438 billion
Allowed Regulated Profit	Rs.3.42 billion
Profit Recorded FY 2013 to FY 2018	Rs.4.21 billion
Profit after adjustment	Rs.2.85 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.80 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.26 billion
Additional Profitability over Remaining Life of Contract	Rs.0.60 billion
Additional Profitability over Life of Project	Rs.0.86 billion

Foundation Wind Energy-I LIMITED (FWEL-I)

Background	
Ownership Structure	Fauji Foundation
Size of Plant	50 MW
Location of Plant	Gharo, District Thatta, Sindh Province
CoD	April 11, 2015
Details of Tariff	
Original Tariff for FEWL-I granted on	March 16, 2012
Tariff Petition Submitted on	September 9, 2011
Tariff Petition Admitted on	September 14, 2011
Tariff (Cost Plus) Granted to FEWL-I on	March 16, 2012
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 128.703 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Biannual basis
Tariff Adjustment after CoD Allowed on	October 27, 2016

Capital Structure and Project set-up cost (USD million)		**Determination 08-05-2012**	**COD Determination 27-10-2016**
	Equity	*32.176*	*30.114*
	Total debt	*96.527*	*95.360*
	Total Project Cost	***128.702***	***125.473***
	Debt to Equity Ratio	*75:25*	*74:26*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 08-05-2012**	**COD Determination 27-10-2016**
	EPC Cost	**111.939**	**110.272**
	Non-EPC costs	1.188	3.750
	Project development costs	3.040	
	Land cost	0.099	-
	Duties and taxes	0.711	0.689
	Pre-COD insurance	1.511	1.039
	Financial charges	3.519	2.604
	Working capital	1.037	-
	Interest During Construction	5.658	7.119
	Total Project Cost	***128.702***	***125.473***

REVIEW OF PROFITABILITY AND DIVIDENDS

612. To determine the profitability and dividend history of FFCEL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends
1.7.2015 till 30.6.2019

Capital Injected by Sponsors	Rs.3.502 billion
Allowed Regulated Profit	Rs.2.93 billion
Profit Recorded FY 2015 to FY 2019	Rs.4.05 billion
Profit after adjustment	Rs.3.07 billion
Excess Profit	Rs.0.145 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.15 billion

DETAILS OF EXCESS PROFIT OVER REGULATORY RETURN

613. A comparison of Adjusted Profits generated from operations with allowed regulatory returns during the period 2015 to 2019 revealed that FWEL – I has earned an Excessive Profit of Rs.0.145 billion. Detailed working of the excess profit is as follows:

Details of Excess Profit Over Regulatory Return – Rs. in Billion
1.7.2015 till 30.6.2019

Description	**2019**	**2018**	**2017**	**2016**	**2015**	**Total**
Accounting Profit / (Loss) Before tax	1.217	0.940	1.149	0.742	0.003	4.051
Depreciation	0.672	0.626	0.625	0.633	0.141	2.698
Finance Cost Long term	0.655	0.531	0.542	0.598	0.163	2.489
Debt Service Cost	-1.470	-1.574	-1.418	-1.363	-0.450	-6.274
Finance Cost Short Term	0.004	0.029	0.051	0.098	0.012	0.194
Assets Written off	0.000	0.000	0.000	0.000	0.002	0.002
Donation	0.002	0.002	0.001	0.000	0.000	0.005
Other Income	-0.055	-0.014	-0.007	-0.008	-0.008	-0.093
Adjusted Profit	**1.025**	**0.541**	**0.942**	**0.701**	**-0.137**	**3.072**
Allowed Regulatory Return	**0.922**	**0.465**	**0.535**	**0.768**	**0.237**	**2.927**
Excess return	**0.103**	**0.076**	**0.407**	**-0.067**	**-0.374**	**0.145**

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.22 billion
Additional Profitability over Remaining Life of Contract	Rs.0.66 billion
Additional Profitability over Life of Project	Rs.0.88 billion

Hydro China Dawood Power (Pvt.) Limited (DPPL)

Background	
Formerly	Dawood Power (Pvt.) Limited (formerly Win Power (Pvt.) Limited (WPL)
Size of Plant	50 MW
Location of Plant	Gharo, District Thatta, Sindh Province
Details of Tariff	
Original Tariff for DPPL granted on	December 6, 2008
Tariff Petition Submitted on	July 16, 2008
Tariff Petition re-Submitted on	May 2013
Tariff (Cost Plus) Granted to DPPL on	December 6, 2008
Tariff (Upfront) Granted to DPPL on	April 23, 2014
Tariff Control Period sought	20 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 133.140 million
IRR Allowed	17% for a period of 20 years
Debt Repayment Period allowed	10 years with repayment schedule on a Biannual basis
Tariff Adjustment after CoD Allowed on	October 27, 2016

Capital Structure and Project set-up cost (USD million)		**Tariff Determination 06-12-2008**
	Equity	*26.628*
	Total debt	*106.512*
	Total Project Cost	***133.140***
	Debt to Equity Ratio	*80:20*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 06-12-2008**
	EPC Cost	**119.933**
	Project development and management	3.739
	Fee and other non-EPC costs	1.210
	Financing fee/charges	4.656
	Interest During Construction	3.602
	Total Project Cost	***133.140***

REVIEW OF PROFITABILITY AND DIVIDENDS

614. To determine the profitability and dividend history of DPPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends 1.7.2016 till 30.6.2019	
Capital Injected by Sponsors	Rs.3.466 billion
Allowed Regulated Profit	Rs.1.82 billion
Profit Recorded FY 2016 to FY 2019	Rs.2.80 billion
Profit after adjustment	Rs.1.46 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.88 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.08 billion
Additional Profitability over Remaining Life of Contract	Rs.0.43 billion
Additional Profitability over Life of Project	Rs.0.50 billion

Quaid-E-Azam Solar Power (Private) Limited (QASPL)

Background	
Ownership Structure	Owned by the Government of Pakistan
Size of Plant	100 MW
Location of Plant	LalSohanra in Cholistan, District Bahawalpur, Punjab Province
CoD	July 15, 2015
Details of Tariff	
Original Tariff for QASPL granted on	January 22, 2015 & June 2, 2016
Tariff Petition Submitted on	-
Tariff (Upfront) Petition re-Submitted on	February 25, 2015
Tariff Petition Admitted on	February 27, 2015
Tariff (Cost plus) Granted to QASPL on	January 22, 2015
Tariff (Upfront) Granted to QASPL on	June 2, 2016
Tariff Control Period sought	25 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 124.907 million
IRR Allowed	17% for a period of 25 years
Debt Repayment Period allowed	10 years with repayment schedule on a Quarterly basis
Tariff Adjustment after CoD Allowed on	June 2, 2016

Capital Structure and Project set-up cost (USD million)		**Determination 22-01-2015**	**COD Determination 02-06-2016**
	Equity	*37.858*	*37.655*
	Total debt	*113.573*	*112.964*
	Total Project Cost	***151.431***	***150.619***
	Debt to Equity Ratio	*75:25*	*75:25*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 22-01-2015**	**COD Determination 02-06-2016**
	EPC Cost	***131.150***	***131.150***
	Duties and taxes	*4.737*	*2.457*
	Non-EPC cost	*4.350*	*4.351*
	Project development cost	*3.666*	*3.665*
	Insurance during construction	*1.019*	*1.019*
	Financing fee and charges	*3.804*	*3.804*
	Interest during construction	*2.705*	*4.172*
	Total Project Cost	***151.431***	***150.618***

REVIEW OF PROFITABILITY AND DIVIDENDS

615. To determine the profitability and dividend history of QASPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant

publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends ***1.7.2015 till 30.6.2019***	
Capital Injected by Sponsors	Rs.3.81 billion
Allowed Regulated Profit	Rs.3.77 billion
Profit Recorded FY 2016 to FY 2019	Rs.5.39 billion
Profit after adjustment	Rs.1.86 billion
Excess Profit	Rs.0.00 billion (*Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.2.20 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.28 billion
Additional Profitability over Remaining Life of Contract	Rs.1.50 billion
Additional Profitability over Life of Project	Rs.1.78 billion

Apollo Solar Development Pakistan Limited (ASDPL)

Background	
Size of Plant	100 MW
Location of Plant	LalSohanra in Cholistan, District Bahawalpur, Punjab Province
CoD	May 31, 2016
Details of Tariff	
Original Tariff for ASDPL granted on	January 22, 2015
Tariff Petition Submitted on	-
Tariff (Upfront) Petition re-Submitted on	Marcy 20, 2015
Tariff (Cost plus) Granted to ASDPL on	January 22, 2015
Tariff (Upfront) Granted to ASDPL on	May 26, 2015
Tariff Control Period sought	25 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 151.431 million
IRR Allowed	17% for a period of 25 years
Debt Repayment Period allowed	10 years with repayment schedule on a Quarterly basis
Tariff Adjustment after CoD Allowed on	November 16, 2017

Capital Structure and Project set-up cost (USD million)		**Determination 26-05-2015**	**COD Determination 16-11-2017**
	Equity	*37.858*	*31.322*
	Total debt	*113.573*	*117.832*
	Total Project Cost	***151.431***	***149.152***
	Debt to Equity Ratio	*75:25*	*79:21*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 26-05-2015**	**COD Determination 16-11-2017**
	EPC Cost	**131.150**	**131.150**
	Duties and taxes	4.737	2.160
	Non-EPC cost	4.350	4.350
	Project development cost	3.666	3.665
	Insurance during construction	1.019	1.019
	Financing fee and charges	3.804	3.804
	Interest during construction	2.705	2.280
	Sinosure Fee	-	0.724
	Total Project Cost	***151.431***	***149.152***

REVIEW OF PROFITABILITY AND DIVIDENDS

616. To determine the profitability and dividend history of ASDPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends *1.1.2016 till 31.12.2018*	
Capital Injected by Sponsors	Rs.3.45 billion
Allowed Regulated Profit	Rs.1.81 billion
Profit Recorded FY 2016 to FY 2018	Rs.2.58 billion
Profit after adjustment	Rs.1.52 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.66 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.14 billion
Additional Profitability over Remaining Life of Contract	Rs.1.00 billion
Additional Profitability over Life of Project	Rs.1.14 billion

Best Green Energy Pakistan Limited (BGEPL)

Background	
Size of Plant	100 MW
Location of Plant	LalSohanra in Cholistan, District Bahawalpur, Punjab Province
CoD	May 31, 2016
Details of Tariff	
Original Tariff for BGEPL granted on	January 22, 2015
Tariff Petition Submitted on	-
Tariff (Upfront) Petition re-Submitted on	Marcy 3, 2015
Tariff (Cost plus) Granted to BGEPL on	January 22, 2015
Tariff (Upfront) Granted to BGEPL on	May 26, 2015
Tariff Control Period sought	25 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 151.431 million
IRR Allowed	17% for a period of 25 years
Debt Repayment Period allowed	10 years with repayment schedule on a Quarterly basis
Tariff Adjustment after CoD Allowed on	-

Capital Structure and Project set-up cost (USD million)		**Determination 26-05-2015**	**COD Determination 16-11-2017**
	Equity	*37.858*	*31.322*
	Total debt	*113.573*	*117.832*
	Total Project Cost	***151.431***	***149.152***
	Debt to Equity Ratio	*75:25*	*79:21*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 26-05-2015**	**COD Determination 16-11-2017**
	EPC Cost	**131.150**	**131.150**
	Duties and taxes	4.737	2.160
	Non-EPC cost	4.350	4.350
	Project development cost	3.666	3.665
	Insurance during construction	1.019	1.019
	Financing fee and charges	3.804	3.804
	Interest during construction	2.705	2.280
	Sinosure Fee	-	0.724
	Total Project Cost	***151.431***	***149.152***

REVIEW OF PROFITABILITY AND DIVIDENDS

617. To determine the profitability and dividend history of BGEPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends 1.1.2016 till 31.12.2018	
Capital Injected by Sponsors	Rs.3.23 billion
Allowed Regulated Profit	Rs.1.56 billion
Profit Recorded FY 2016 to FY 2018	Rs.1.38 billion
Profit after adjustment	Rs.1.41 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.19 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.12 billion
Additional Profitability over Remaining Life of Contract	Rs.0.86 billion
Additional Profitability over Life of Project	Rs.0.98 billion

Crest Energy Pakistan Limited (CEPL)

Background	
Size of Plant	100 MW
Location of Plant	LalSohanra in Cholistan, District Bahawalpur, Punjab Province
CoD	May 31, 2016
Details of Tariff	
Original Tariff for BGEPL granted on	January 22, 2015
Tariff Petition Submitted on	-
Tariff (Upfront) Petition re-Submitted on	Marcy 20, 2015
Tariff (Cost plus) Granted to BGEPL on	January 22, 2015
Tariff (Upfront) Granted to BGEPL on	May 26, 2015
Tariff Control Period sought	25 years
EPC Project	Turney basis – no detail of equipment provided
Project Cost allowed	USD 151.431 million
IRR Allowed	17% for a period of 25 years
Debt Repayment Period allowed	10 years with repayment schedule on a Quarterly basis
Tariff Adjustment after CoD Allowed on	

Capital Structure and Project set-up cost (USD million)		**Determination 26-05-2015**	**COD Determination 16-11-2017**
	Equity	*37.858*	*36.781*
	Total debt	*113.573*	*112.676*
	Total Project Cost	***151.431***	***149.457***
	Debt to Equity Ratio	*75:25*	*75.39:24.61*

Details of EPC, total project cost (USD million) and changes on account of foreign currency fluctuations	**Project Costs**	**Tariff Determination 26-05-2015**	**COD Determination 16-11-2017**
	EPC Cost	**131.150**	**131.150**
	Duties and taxes	4.737	2.234
	Non-EPC cost	4.350	4.350
	Project development cost	3.666	3.665
	Insurance during construction	1.019	1.019
	Financing fee and charges	3.804	3.804
	Interest during construction	2.705	2.551
	Sinosure Fee	-	0.684
	Total Project Cost	***151.431***	***149.457***

REVIEW OF PROFITABILITY AND DIVIDENDS

618. To determine the profitability and dividend history of CEPL, the financial statements, documents provided by NEPRA, PPIB and CPPA-G and the relevant publicly available information were reviewed for the period starting from CoD till June 30, 2019. Details are as follows:

Review of Profitability and Dividends *1.1.2016 till 31.12.2018*	
Capital Injected by Sponsors	Rs.3.83 billion
Allowed Regulated Profit	Rs.1.94 billion
Profit Recorded FY 2016 to FY 2018	Rs.1.89 billion
Profit after adjustment	Rs.1.89 billion
Excess Profit	Rs.0.00 billion *(Allowed Regulated Profit - Profit after adjustment)*
Amount withdrawn from Profits as Dividend	Rs.0.46 billion

ADDITIONAL PROFITABILITY ON ACCOUNT OF INCORRECT IRR CALCULATION

Incorrect Calculation of IRR Built in Tariff – 18.39% instead of 17%	
NEPRA Allowed RoE Payment Frequency	Annually
Actual RoE Payment Frequency	Monthly
IRR Earned because of Mismatch in Payment Frequency	17%
Additional Profitability because of Excess IRR Paid (%age)	8.18% (1.39/17)
Additional Profitability because of Excess IRR Paid (Amount)	Rs.0.15 billion
Additional Profitability over Remaining Life of Contract	Rs.1.08 billion
Additional Profitability over Life of Project	Rs.1.22 billion

JDW Sugar Mills Limited Bagasse Power Plants at JDW Sugar Mills Unit-II (26.35 MW) and Unit-III (26.35 MW) (JDW)

Background	
Date of Incorporation	• On May 31, 1990 as private limited company • Converted to public limited company on August 24, 1991 • Listed on Pakistan Stock Exchange
Type of Plant	Bagasse based Co-Generation
EPA with CPPA-G since	March 20, 2014
Location of Plant	• JDW Unit-II, Sadiqabad, Rahim Yar Khan, Punjab • JDW Unit-III, Ghotki, Sindh
CoD	Unit II on June 12, 2014 Unit III on October 3, 2014

REVIEW OF FINANCIAL STATEMENTS

619. The financial statements of JDW were reviewed to arrive at an Adjusted Profit in line with the methodology discussed in "Detailed Review Of Profitability And Dividends – Methodology" under the section "Power Generation Policy 2002".

620. The main business activity of JDW Sugar Mills Limited is production of sugar, therefore the required information pertaining to power generation was not available in its financial statements. However, the collective Adjusted Profit pertaining to projects JDW-II and JDW-III were calculated using information reported in the Group Reportable Segment under the head "Co-Generation segment" in the consolidated financial statements of JDW Sugar Mills Limited.

621. The adjusted profit was compared with the allowed RoE to identify an excess profit of **Rs. 3.85 billion** made by the two projects JDW-II and JDW-II, details of which are tabulated below:

	30-Sep	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	Total Rs.
	Profit before tax	123,517,157	1,244,322,076	1,510,511,811	2,039,658,102	1,910,423,319	1,250,229,327	8,078,661,792
Add:	Depreciation	47,518,605	346,216,614	331,885,870	312,948,859	293,496,250	274,450,973	1,606,517,171
Add:	Finance cost	75,836,298	520,369,425	387,551,146	336,255,441	398,204,643	974,686,861	2,692,903,814
Less:	Debt service JDW II	226,752,791	596,096,690	526,642,114	569,131,900	588,449,013	789,647,845	3,296,720,353
Less:	Debt service JDW III	-	621,671,204	510,171,883	550,660,245	629,325,162	624,715,939	2,936,544,433
Less:	Working Cap JDW II	10,083,720	25,893,413	20,487,627	21,603,104	22,507,869	37,023,534	137,599,266
Less:	Working Cap JDW III	-	27,108,067	19,855,790	20,899,111	24,057,347	28,765,502	120,685,818
Adjusted profit		**10,035,549**	**840,138,741**	**1,152,791,413**	**1,526,568,042**	**1,337,784,821**	**1,019,214,341**	**5,886,532,907**
ROE allowed	JDW II	60,199,753	165,171,414	174,197,030	188,806,339	204,378,631	279,600,718	1,072,353,886
ROE allowed	JDW III	-	171,091,323	168,697,120	188,157,283	218,280,017	218,120,717	964,346,460
Total ROE		**60,199,753**	**336,262,737**	**342,894,150**	**376,963,622**	**422,658,648**	**497,721,435**	**2,036,700,346**
Excess return		**(50,164,204)**	**503,876,004**	**809,897,262**	**1,149,604,420**	**915,126,173**	**521,492,906**	**3,849,832,561**

622. In order to determine the reasons for excess profit, the reasonableness of the tariff determination of JDW was reviewed. The assumption of a plant factor of 45% as used in the tariff determination was corroborated with the actual plant utilization (annual Net Electrical Output) leading to the following findings:

ACTUAL ENERGY GENERATION – EXCESSIVE GAINS OF RS. 4 BILLION

623. JDW-II and JDW-III were producing electricity in excess of the 45% presumed plant factor in the tariff determination. The recovery of fixed cost and debt service cost has already been accounted for in this, meaning that any electricity production in excess of 45% would result in excess recovery of fixed cost and debt service cost.

624. The actual recovery of such cost is linked with actual energy production rather than plant factor determined at 45%. Detail of the excess gains earned by the two projects aggregating to **Rs. 3,959,697,911** on this account is tabulated below:

Year	Net Electrical Output	Payment on account of fixed components	Output at 45% (PPA contract capacity) (24.37MW x 45% x 365 x 24)	Payment on account of fixed components @ 45%	Excessive gains
	kWh	Rs.	kWh	Rs.	Rs.
JDW-II					
2014-2015	159,206,730	898,674,229	96,066,540	542,266,798	356,407,430
2015-2016	159,539,006	806,642,271	96,066,540	485,720,288	320,921,983
2016-2017	177,615,206	878,662,623	96,066,540	475,241,280	403,421,343
2017-2018	183,250,887	929,640,726	96,066,540	487,350,264	442,290,462
2018-2019	185,537,600	1,092,810,922	96,066,540	565,829,051	526,981,871
				Sub-total	**2,050,023,088**
JDW-III			**(24.41MW x 45% x 365 x 24)**		
2014-2015	165,329,432	909,215,004	96,224,220	529,176,829	380,038,175
2015-2016	158,196,578	785,650,061	96,224,220	477,877,368	307,772,693
2016-2017	170,987,552	856,329,551	96,224,220	481,904,340	374,425,211
2017-2018	189,237,263	980,622,177	96,224,220	498,631,204	481,990,973
2018-2019	154,923,720	964,514,659	96,224,220	599,066,887	365,447,772
				Sub-total	**1,941,438,458**
				Total	**3,959,697,911**

RYK Mills Limited Bagasse Power Plant (30 MW)

Background	
Type of Plant	Bagasse fired electric power generation facility
EPA with CPPA-G since	October 10, 2014
Location of Plant	Rakanabad, Rahim Yar Khan, Punjab
CoD	March 23, 2015

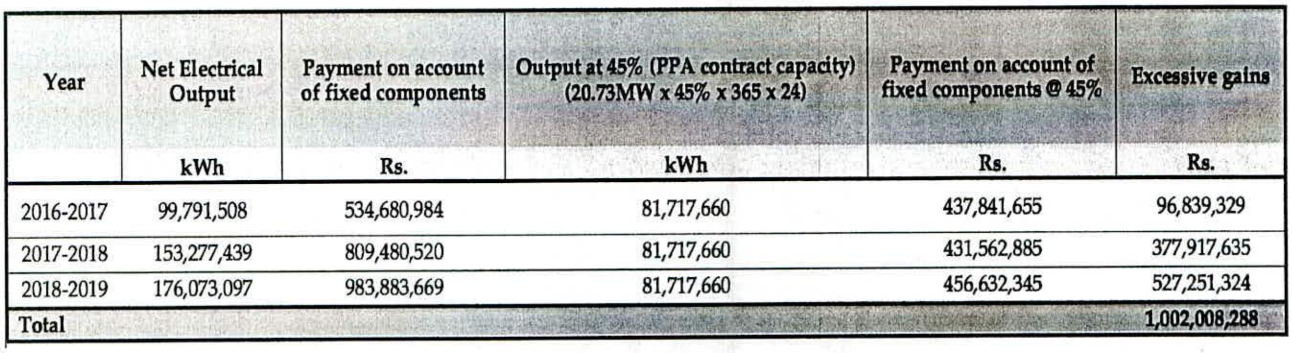
REVIEW OF FINANCIAL STATEMENTS

625. The financial statements of RYK were reviewed to arrive at an Adjusted Profit in line with the methodology discussed earlier. Since the main business of RYK is production of sugar, the requisite information pertaining to power generation was not available in its financial statements. Therefore, it was not possible to calculate the Adjusted Profit pertaining to RYK Bagasse Power Plant directly. However, based on the findings in JDW-II and JDW-III, a similar exercise was conducted regarding the assumption of plant factor of 45% used in the tariff determination and was corroborated with the actual plant utilization (annual Net Electrical Output), details of which are as follows:

ACTUAL ENERGY GENERATION – EXCESSIVE GAINS OF RS. 1 BILLION

626. RYK was producing electricity in excess of the 45% presumed plant factor in the tariff determination. The recovery of fixed cost and debt service cost has already been accounted for in this, meaning that any electricity production in excess of 45% would result in excess recovery of fixed cost and debt service cost.

627. The actual recovery of such cost is linked with actual energy production rather than plant factor determined at 45% by NEPRA. Detail of the excess gains earned by the project aggregating to **Rs. 1,002,008,288** on this account is tabulated below:



Year	Net Electrical Output	Payment on account of fixed components	Output at 45% (PPA contract capacity) (20.73MW x 45% x 365 x 24)	Payment on account of fixed components @ 45%	Excessive gains
	kWh	Rs.	kWh	Rs.	Rs.
2016-2017	99,791,508	534,680,984	81,717,660	437,841,655	96,839,329
2017-2018	153,277,439	809,480,520	81,717,660	431,562,885	377,917,635
2018-2019	176,073,097	983,883,669	81,717,660	456,632,345	527,251,324
Total					1,002,008,288

Chiniot Power Limited (CPL)

Background	
Date of Incorporation	August 25, 2013 (Public Limited Company)
Type of Plant	Bagasse fired electric power generation facility
Size of Plant	31.2 MW x 2
Location of Plant	Chiniot Jhang Road, Chiniot, Punjab
CoD	November 29, 2015

REVIEW OF FINANCIAL STATEMENTS

628. Since the financial statements of CPL were only available for the first two years, it was not possible to completely review the financials of the company. However, based on the findings in JDW-II and JDW-III, a similar exercise was conducted regarding the assumption of plant factor of 45% used in the tariff determination and was corroborated with the actual plant utilization (annual Net Electrical Output) as per information provided by CPPA-G. Details of findings are as follows:

ACTUAL ENERGY GENERATION – EXCESSIVE GAINS OF RS. 1.3 BILLION

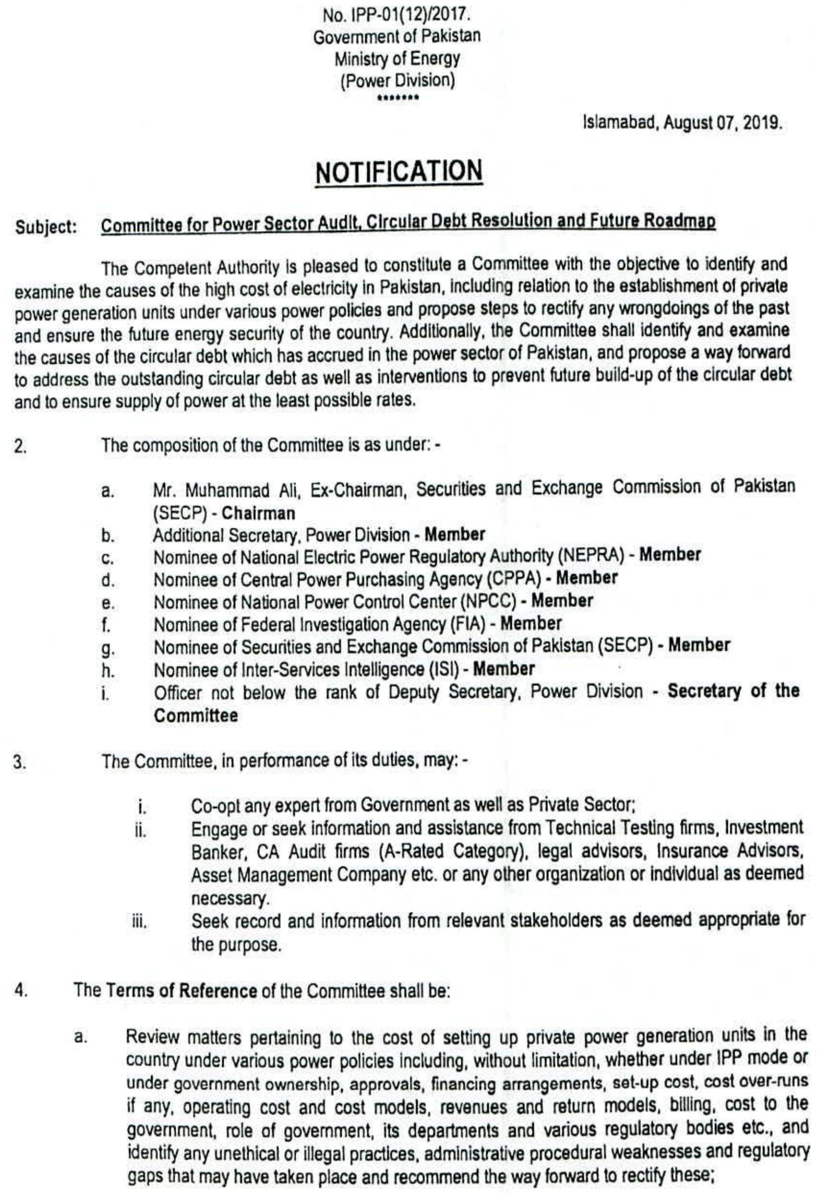
629. CPL was producing electricity in excess of the 45% presumed plant factor in the tariff determination. The recovery of fixed cost and debt service cost has already been accounted for in this, meaning that any electricity production in excess of 45% would result in excess recovery of fixed cost and debt service cost.

630. The actual recovery of such cost is linked with actual energy production rather than plant factor determined at 45% by NEPRA. Details of the excess gains earned by the project aggregating to **Rs. 1,337,081,467** on this account is tabulated below:

Year	**Net Electrical Output**	**Payment on account of fixed components**	**Output at 45% (PPA contract capacity) (56.78 x 45% x 365 x 24)**	**Payment on account of fixed components @ 45%**	**Excessive gains**
	kWh	**Rs.**	**kWh**	**Rs.**	**Rs.**
2015-2016	261,685,357	1,404,924,093	223,826,760	1,201,670,630	203,253,463
2016-2017	325,764,279	1,736,251,438	223,826,760	1,192,947,045	543,304,393
2017-2018	336,012,627	1,768,702,199	223,826,760	1,178,178,589	590,523,611
Total					**1,337,081,467**

ANNEXURES

Annexure A – Terms of Reference and Composition of the Committee



No. IPP-01(12)/2017.
Government of Pakistan
Ministry of Energy
(Power Division)
****

Islamabad, August 07, 2019.

NOTIFICATION

Subject: **Committee for Power Sector Audit, Circular Debt Resolution and Future Roadmap**

The Competent Authority is pleased to constitute a Committee with the objective to identify and examine the causes of the high cost of electricity in Pakistan, including relation to the establishment of private power generation units under various power policies and propose steps to rectify any wrongdoings of the past and ensure the future energy security of the country. Additionally, the Committee shall identify and examine the causes of the circular debt which has accrued in the power sector of Pakistan, and propose a way forward to address the outstanding circular debt as well as interventions to prevent future build-up of the circular debt and to ensure supply of power at the least possible rates.

2. The composition of the Committee is as under: -

  a. Mr. Muhammad Ali, Ex-Chairman, Securities and Exchange Commission of Pakistan (SECP) - **Chairman**
  b. Additional Secretary, Power Division - **Member**
  c. Nominee of National Electric Power Regulatory Authority (NEPRA) - **Member**
  d. Nominee of Central Power Purchasing Agency (CPPA) - **Member**
  e. Nominee of National Power Control Center (NPCC) - **Member**
  f. Nominee of Federal Investigation Agency (FIA) - **Member**
  g. Nominee of Securities and Exchange Commission of Pakistan (SECP) - **Member**
  h. Nominee of Inter-Services Intelligence (ISI) - **Member**
  i. Officer not below the rank of Deputy Secretary, Power Division - **Secretary of the Committee**

3. The Committee, in performance of its duties, may: -

  i. Co-opt any expert from Government as well as Private Sector;
  ii. Engage or seek information and assistance from Technical Testing firms, Investment Banker, CA Audit firms (A-Rated Category), legal advisors, Insurance Advisors, Asset Management Company etc. or any other organization or individual as deemed necessary.
  iii. Seek record and information from relevant stakeholders as deemed appropriate for the purpose.

4. The **Terms of Reference** of the Committee shall be:

  a. Review matters pertaining to the cost of setting up private power generation units in the country under various power policies including, without limitation, whether under IPP mode or under government ownership, approvals, financing arrangements, set-up cost, cost over-runs if any, operating cost and cost models, revenues and return models, billing, cost to the government, role of government, its departments and various regulatory bodies etc., and identify any unethical or illegal practices, administrative procedural weaknesses and regulatory gaps that may have taken place and recommend the way forward to rectify these;

1

b. Review matters pertaining to the 'circular debt' in the country, including, without limitation, the cause of build-up of 'circular debt', examine payments made from time to time to clear outstanding dues to the independent power producers, examine causes for under collection of revenue by DISCOs, electricity tariff determination policies and procedures, systemic issues which may have exacerbated the situation, etc., and identify any unethical or illegal practices, administrative and procedural weaknesses and regulatory gaps that may have taken place and recommend the way forward to remedy these;

c. Review policies and models of power sector globally and recommend the way forward for changes in the country's power policy and structure of the sector, including, without limitation, generation, transmission, distribution, organizational set-ups, regulatory reform, governance reform, financial clearing, market-based mechanisms, etc., with a view to ensure avoidance of circular debt in the future and reduction of cost of power to consumers;

d. To review the compliance of IPPs with parameters and terms and conditions of various agreements signed with relevant Government Agencies / Bodies which shall include, without limitation, the under mentioned areas: -

  i. Any relaxations given to IPPs in violation of policies / rules, including but not limited to:
    a. Tariff determination
    b. Financial closure
    c. Construction period
    d. Capacity payments
    e. Merit Order, etc.
  ii. Efficiency (Machine as well as plant / fuel) allowed in tariff and actual efficiency, frequency of efficiency verification, fuel costs and inventory etc.
  iii. Cost accounting mechanism and review of various cost components; and
  iv. Review of technology, capital costs and financial structure submitted for tariff determination.

5. The Committee to submit phase-wise findings / reports, from start date, to Prime Minister as under:

a. First Interim Report will be submitted within a period of six (06) weeks;
b. Second Interim Report will be submitted within a period of ten (10) weeks; and
c. Final consolidated report will be submitted within twelve (12) weeks.

6. Following logistic support shall be provided to the Committee for efficient and smooth functioning:

a. Secretariat support for accomplishment of assigned task.
b. Provision of office building and support mechanism.

(Rao M. Rizwan Ahsan)
Section Officer (IPP)
Tele: 9223090

cc:

i. Secretary to Prime Minister, Prime Minister Office, Islamabad.
ii. SO to Minster for Energy (Power Division).
iii. SO to Secretary, Power Division.
iv. SPS to Additional Secretary (I) & (II), Power Division.
v. Members of the Committee.
vi. Office file.

Annexure B – Presentations and Meetings

	Presentations
	Dr. Fiaz Ahmad Chaudhry
	K-Electric
	National Electric Power Regulatory Authority
	Central Power Purchasing Agency
	Private Power & Infrastructure Board
	Alternative Energy Development Board
	National Transmission & Despatch Company Limited
	IGCEP Team – NTDC
	Pakistan Electric Power Company
	Hyderabad Electric Supply Corporation
	Sukkur Electric Supply Corporation
	Faisalabad Electric Supply Corporation
	Peshawar Electric Supply Corporation
	Islamabad Electric Supply Corporation
	NAB Lahore
	NAB Rawalpindi
	NAB Awareness & Prevention Team
	Meetings
	Mr. Omer Ayub – Federal Minister for Energy
	Mr. Asad Umer – Federal Minister for Planning, Development, Reforms and Special Initiatives
	Mr. Shibli Faraz – Senator
	Mr. Irfan Ali – Secretary, Power
	Mr. Hussain Asghar - Chairman, Debt Commission

	Mr. Tauseef Farooqi – Chairman, NEPRA
	Mr. Saifullah Chatta – Member, NEPRA
	Mr. Akbar Ayub Khan - Member, Energy Task Force
	Mr. Shah Jahan Mirza – MD, PPIB
	Mr. Zargham Eshaq Khan – JS, MoE (PD)
	Mr. Abid Lodhi – CEO, CPPA-G
	Mr. Ayub - NPCC
	Mr. Rihan Akhter – CFO, CPPA-G
	Mr. Sajid Akram – ADG, NEPRA
	Mr. Salis Usman - GM Planning, NTDC
	Mr. Adil Shareef – PPIB
	Mr. Safeer Ahmed – PPIB
	Mr. Irfan Yousuf - AEDB
	Mr. Sheeraz Anwar - AEDB
	Mr. Khalid Mansoor - IPP Association
	Mr. Salahuddin Rifai - ex GM, WAPDA
	Mr. Masood Akhtar - ex GM, NPCC
	Barrister Asghar Khan - Lawyer
	Mr. Rana Amjad - ex GM, WPPO
	Mr. Aamir Ghaziani - CFO, KE
	Mr. Mian Ahmad Ibrahim - Former Lawyer, NEPRA
	Mr. Tahir Moeen - SE, PESCO
	Ms. Nida Farid – Founder, Save Joules
	Fitchner gmbH – Dubai
	Mott Macc Donald UK – Dubai

	Energoprojekt Entel- Dubai
	ECA Consulting UK (Video Conference)
	SAARC Energy Centre, Islamabad
	Representatives of USAID

Annexure 1A – IPPs: Sponsors, Location and Operations

	Name of IPP	Owner	Location	Gross Capacity (MW)	Fuel	Policy	CoD Date	Term (Yrs.)	Date of Expiry	Remaining life
1	Hub Power Co.	Habibullah group	Tehsil Hub, District Lasbela, Balochistan	1292	RFO	1994	31st Mar 1997	30	31st Mar 2027	7
2	Lalpir Ltd.	Mansha Group	Mehmood Kot Muzaffargarh Punjab	362	RFO	1994	6th Nov 1997	30	6th Nov 2027	7
3	Pak Gen (Pvt.) Ltd.	Mansha Group	Mehmood Kot Muzaffargarh Punjab	365	RFO	1994	1st Feb 1998	30	1st Feb 2028	8
4	Altern Energy Ltd.	Saudi Arabian Construction & Repair Co.	Fateh Jung Attock	31	Gas	1994	6th Jun 2001	30	6th Jun 2031	11
5	Fauji Kabirwala Power Co. Ltd.	Fauji Foundation	Kabirwala District, Khanewal	157	Gas	1994	21st Oct 1999	30	21st Oct 2029	9
6	Gul Ahmed Energy	Gul Ahmed Group	Korangi Town, Karachi	136	RFO	1994	3rd Nov 1997	22	3rd Nov 2019	0
7	Habibullah Coastal Power (Pvt) Co.	JS Group	Quetta	140	Gas	1994	11th Sep 1999	30	11th Sep 2029	9
8	Japan Power Generation Co.	Pak Oman Investment Company Summit Bank Ltd.	Raiwind Road, near Jia Bagga	120	RFO	1994	14th Mar 2000	30	14th Mar 2030	10
9	Kohinoor Energy Ltd.	Naseem Saigol Group	Raiwind-Manga road near Lahore	131	RFO	1994	20th Jun 1997	22	20th Jun 2019	0
10	Liberty Power Ltd.	Tenaga Nasional Berhad (TNB) - Malaysian Government	Daharki District Ghotki Sindh	235	Low Btu Gas	1994	10th Sep 2001	25	10th Sep 2026	6
11	Rousch (Pakistan) Power Ltd.	Razzak Dawood group	Abdul Hakeem (near Sidhnai barrage) District Khanewal	450	Gas	1994	11th Dec 1999	30	11th Dec 2029	9
12	Saba Power Co.	Nadeem Babar	Farooqabad Sheikhupura Punjab	134	RFO	1994	31st Dec 1999	30	31st Dec 2029	9
13	Southern Electric Power Co. Ltd.	Ali Mahmood	Raiwind Lahore	117	RFO	1994	12th Jul 1999	30	12th Jul 2029	9
14	Tapal Energy Pvt Ltd.	Tapal group	District West Karachi	126	RFO	1994	20th Jun 1997	22 Years	20th Jun 2019	0
15	Uch Power Ltd.	Engie France	Dera Murad Jamali, District Naseerabad, Balochistan	586	Low Btu Gas	1994	18th Oct 2000	30	18th Oct 2030	10
16	Davis Energy Power Ltd.	Syeda Ummekulsum Imam Syed Abid Imam	Toba Tek Singh District Jhang, Punjab	11	Gas	1994	13th Jul 2013	30	13th Jul 2043	23
17	Kot Addu Power Company Ltd.	Pakistan WAPDA KAPCO Employees Empowerment Trust	Kot Addu, District Muzzafargarh, Punjab	1638	Gas & RFO	1994	Dec 1996	25	Dec 2021	1
18	Laraib Energy Ltd.	Habibullah group	7th km downstream Mangla Dam, AJK	84	Hydro	1995	23rd Mar 2013	25	23rd Mar 2038	18
19	Attock Gen Ltd.	Attock group	Morgah Rawalpindi	165	RFO	2002	17th Mar 2009	25	17th Mar 2034	14
20	Atlas Power Ltd.	Shirazi group	Sheikhupura, Punjab	225	RFO	2002	18th Dec 2009	25	18th Dec 2034	14
21	Engro Energy Ltd.	Hussain Dawood group	Qadirpur, District Ghotki, Sindh	227	Low Btu Gas	2002	27th Mar 2010	25	27th Mar 2035	15
22	Saif Power Ltd.	Saifullah group	Sahiwal, Punjab	229	Gas/RLNG	2002	27th Apr 2010	30	27th Apr 2040	20
	more Power Generation Co. Ltd.	Mian Karimuddin Family	Bhikki, District Sheikhupura, Punjab	225	Gas/RLNG	2002	16th Jun 2011	30	16th Jun 2041	21
24	Narowal Energy Ltd.	Habibullah group	Narowal, Punjab	220	RFO	2002	22nd Apr 2011	25	22nd Apr 2036	16
25	Liberty Power Tech Ltd.	Mukaty group	Faisalabad (near M3 Industrial State)	200	RFO	2002	13th Jan 2011	25	13th Jan 2036	16
26	Nishat Power Ltd.	Mansha Group	near Lahore	200	RFO	2002	9th Jun 2010	25	9th Jun 2035	15
27	Nishat Chunian Ltd.	Mansha Group	near Lahore	200	RFO	2002	21st Jul 2010	25	21st Jul 2035	15
28	Orient Power Company Ltd.	Nadeem Babar	Balloki, District Kasur, Punjab	229	Gas/RLNG	2002	24th May 2010	30	24th May 2040	20
29	Foundation Power Co. (Daharki Ltd.)	Fauji Foundation	Daharki District Ghotki Sindh	185	Low Btu Gas	2002	16th May 2011	25	16th May 2036	16
30	Sapphire Electric Company Ltd.	Sapphire group	Muridke, District Sheikhupura, Punjab	225	Gas/RLNG	2002	4th Oct 2010	30	4th Oct 2040	20

31	Uch-II Power Pvt Ltd.	Engie France	Dera Murad Jamali, Balochistan	404	Low Btu Gas	2002	4th Apr 2014	25	4th Apr 2039	19
32	Star Hydro Power Ltd.	KDS Hydro PTE Ltd.	Muzaffarabad, AJK	147	Hydro	2002	8th Nov 2017	30	8th Nov 2047	27
33	NPPMC Pvt Ltd. (Haveli Bahadur Shah Power Project)	Government of Pakistan	Haveli Bahadur Shah, District Jhang, Punjab	1230	RLNG	2015	29th Jul 2018	30	29th Jul 2048	28
34	Quaid-e-Azam Thermal Power Pvt. Ltd.	Government of Punjab	Bhikki, District Sheikhupura, Punjab	1180	RLNG	2015	20th May 2018	30	20th May 2048	28
35	NPPMC Pvt Ltd. (Balloki Power Project)	Government of Pakistan	Balloki, District Kasur, Punjab	1223	RLNG	2015	29th Jul 2018	30	29th Jul 2048	28
36	Huaneng Shandong Ruyi (Pak) Energy Pvt. Ltd.	Huaneng Shandong Ruyi HK Energy	Qadarabad, Sahiwal	1320	imported coal	2015	28th Oct 2017	30	28th Oct 2047	27
37	Port Qasim Electric Power Company Pvt. Ltd.	Port Qasim Energy Dubai Shahzad Shahbaz	Port Qasim, Karachi	1320	imported coal	2015	25th Apr 2018	30	25th Apr 2048	28
38	China Power Hub Generation Company Pvt. Ltd.	China Power International Habibullah group	Hub, Balochistan	1320	imported coal	2015	19th Aug 2019	30	19th Aug 2049	29
39	Engro Powergen Thar (Private) Ltd.	Hussain Dawood group	Thar Sindh	660	Local coal	2015	10th Jul 2019	30	10th July 2049	29
40	FFC Energy Ltd.	Fauji Foundation	Jhimpir	49.5	Wind	RE 2006	16th May 2013	20	16th May 2033	13
41	Zorlu Energy Pakistan Ltd.	Zorlu Enerji Elektrik Uretim A.S.	Jhimpir	56.4	Wind	RE 2006	26th July 2013	20	26th July 2033	13
42	Three Gorges First Wind Farm Pakistan Pvt. Ltd.	China Three Gorges South Asia Investment Limited	Jhimpir	49.5	Wind	RE 2006	25th Nov 2014	20	25th Nov 2034	14
43	Foundation Wind Energy-II Pvt Ltd.	Fauji Foundation	Gharo	50	Wind	RE 2006	10th Dec 2014	20	10th Dec 2034	14
44	Foundation Wind Energy-I Ltd.	Fauji Foundation	Gharo	50	Wind	RE 2006	11th April 2015	20	11th Apr 2035	15
45	Sapphire Wind Power Company Ltd.	Sapphire group	Jhimpir	52.8	Wind	RE 2006	22nd Nov 2015	20	22nd Nov 2035	15
46	Metro Power Company Ltd.	Iqbal Ali Muhammad / Infraco Asia Keenjhar Win	Jhimpir	50	Wind	RE 2006	16th Sept 2016	20	16th Sept 2036	16
47	Yunus Energy Ltd.	Lucky group	Jhimpir	50	Wind	RE 2006	16th Sept 2016	20	16th Sept 2036	16
48	Master Wind Energy Pvt Ltd	Master Textile	Jhimpir	52.8	Wind	RE 2006	14th Oct 2016	20	14th Oct 2036	16
49	Act Wind Pvt Ltd. (formerly Tapal Wind Energy Pvt Ltd.)	Tapal group	Jhimpir	30	Wind	RE 2006	7th Oct 2016	20	7th Oct 2036	16
50	Gul Ahmed Wind Power Ltd.	Iqbal Ali Muhammad / INFRACO AISA / International Finance Corporation	Jhimpir	50	Wind	RE 2006	18th Oct 2016	20	18th Oct 2036	16
51	Tenega Generasi Ltd.	Hussain Dawood group	Gharo	49.5	Wind	RE 2006	11th Oct 2016	20	11th Oct 2036	16
52	Hydro China Dawood Power Pvt Ltd.	Hydrochina International Engineering Co. Rafique Dawood	Gharo	49.5	Wind	RE 2006	5th April 2017	20	5th Apr 2037	17
53	Sachal Energy Development Pvt Ltd.	Arif Habib Group	Jhimpir	49.5	Wind	RE 2006	18th Apr 2017	20	18th Apr 2037	17
54	UEP Wind Power Pvt Ltd.	Super Success Investments Limited - Mauritius	Jhimpir	99	Wind	RE 2006	16th June 2017	20	16th June 2037	17
55	Jhampir Power Pvt Ltd.	JPI holdings Pte Limited	Jhimpir	50	Wind	RE 2006	16th Mar 2018	20	16th Mar 2038	18
56	Hawa Energy Pvt Ltd.	Hawa Holdings / JS Group	Jhimpir	49.6	Wind	RE 2006	15th Mar 2018	20	15th Mar 2038	18
57	Artistic Energy Pvt Ltd.	Artistic Milliners Pvt. Limited	Jhimpir	49.3	Wind	RE 2006	16th Mar 2018	20	16th Mar 2038	18
58	Three Gorges Pakistan Second Wind Farm Pakistan Ltd.	China Three Gorges South Asia Investment Limited	Jhimpir	49.5	Wind	RE 2006	30th June 2018	20	30th June 2038	18

59	Three Gorges Pakistan Third Wind Farm Pakistan Ltd.	China Three Gorges South Asia Investment Limited	Jhimpir	49.5	Wind	RE 2006	9th July 2018	20	9th July 2038	18
60	Tricon Boston Consulting Corporation Pvt Ltd. - A	Sapphire group	Jhimpir	49.6	Wind	RE 2006	16th Aug 2018	20	16th Aug 2038	18
61	Tricon Boston Consulting Corporation Pvt Ltd. - B	Sapphire group	Jhimpir	49.6	Wind	RE 2006	14th Sept 2018	20	14th Sept 2038	18
62	Tricon Boston Consulting Corporation Pvt Ltd. - C	Sapphire group	Jhimpir	49.6	Wind	RE 2006	11th Sept 2018	20	11th Sept 2038	18
63	Zephyr Power Pvt Ltd.	Zia Khaleeli	Gharo	50	Wind	RE 2006	27th Mar 2019	20	27th Mar 2039	19
64	QA Solar Power Pvt Ltd.	Government of Punjab	QASP Bahawalpur	100	Solar	RE 2006	15th July 2015	25	15th July 2040	20
65	Apollo Solar Development Pakistan Ltd.	Apollo Solar Development Hong Kong	QASP Bahawalpur	100	Solar	RE 2006	31st May 2016	25	31st May 2041	21
66	Best Green Energy Pakistan Ltd.	Best Green Energy Limited	QASP Bahawalpur	100	Solar	RE 2006	31st July 2016	25	31st July 2041	21
67	Crest Energy Pakistan Ltd.	Crystal Energy Pakistan	QASP Bahawalpur	100	Solar	RE 2006	31st July 2016	25	31st July 2041	21
68	Harappa Solar Pvt Ltd.	Rana Naseem Ahmed	Harappa Sahiwal	18	Solar	RE 2006	14th Oct 2017	25	14th Oct 2042	22
69	AJ Power Pvt Ltd.	Jehangir Tareen group	Adhi Kot, Khushab Punjab	12	Solar	RE 2006	13th Dec 2017	25	13th Dec 2042	22
70	Oursun Pakistan Ltd.	Nadeem Babar	Gharo, Sindh	50	Solar	RE 2006	12th May, 2018	25	12th May, 2043	23
71	JDW Sugar Mills Ltd (Unit-II)	Jehangir Tareen group	Rahim Yar Khan	26.35	Bagasse	RE 2006	12th June 2014	30	12th June 2044	24
72	JDW Sugar Mills Ltd (Unit-III)	Jehangir Tareen group	Ghotki	26.35	Bagasse	RE 2006	3rd Oct 2014	30	3rd Oct 2044	24
73	Chiniot Power Ltd.	Suleman Shahbaz Sharif group	Faisalabad	57	Bagasse	RE 2006	28th Nov 2015	30	28th Nov 2045	25
74	RYK Mills Ltd.	Makhdum Omar Shahryar	Rahim Yar Khan	30	Bagasse	RE 2006	24th Mar 2015	30	24th Mar 2045	25
75	Hamza Sugar Mills	Mian Muhammad Tayyab	Khanpur Rahimyar Khan	15	Bagasse	RE 2006	10th Mar 2017	30	10th Mar 2047	27
76	Layyah Sugar Mills	Shamim Khan	Layyah	41	Bagasse	RE 2006	1st Dec 2017	30	1st Dec 2047	27
77	Al Moiz Industries Limited	Shamim Khan	Piplan Mianwali	36	Bagasse	RE 2006	4th Jan 2019	30	4th Jan 2049	29
78	Chanar Energy Limited	Javed Ahmad Kayani	Tandlianwala Faisalabad	22	Bagasse	RE 2006	15th Feb 2019	30	15th Feb 2049	29
			Grand total	19,368						

Annexure 1B – 2002 IPPs: Sponsors, Location and Operations

	Name of IPP	Owner	Location	Gross Capacity (MW)	Fuel	CoD Date	Term Yrs.	Remaining life Yrs.
1	Attock Gen Ltd.	Attock group	Morgah Rawalpindi	165	RFO	17.3.2009	25	14
2	Atlas Power Ltd.	Shirazi group	Sheikhupura, Punjab	225	RFO	18.12.2009	25	14
3	Engro Energy Ltd.	Hussain Dawood group	Qadirpur, District Ghotki, Sindh	227	Low Btu Gas	27.3.2010	25	15
4	Saif Power Ltd.	Saifullah group	Sahiwal, Punjab	229	Gas/RLNG	27.4.2010	30	20
5	Halmore Power Generation Co. Ltd.	Mian Karimuddin family	Bhikki, District Sheikhupura, Punjab	225	Gas/RLNG	16.6.2011	30	21
6	Narowal Energy Ltd.	Habibullah group	Narowal, Punjab	220	RFO	22.4.2011	25	16
7	Liberty Power Tech Ltd.	Mukaty group	Faisalabad (near M3 Industrial State)	200	RFO	13.1.2011	25	16
8	Nishat Power Ltd.	Mansha Group	near Lahore	200	RFO	9.6.2010	25	15
9	Nishat Chunian Ltd.	Mansha Group	near Lahore	200	RFO	21.7.2010	25	15
10	Orient Power Company Ltd.	Nadeem Babar	Balloki, District Kasur, Punjab	229	Gas/RLNG	24.5.2010	30	20
11	Foundation Power Company (Daharki Ltd.)	Fauji Foundation	Daharki District Ghotki Sindh	185	Low Btu Gas	16.5.2011	25	16
12	Sapphire Electric Company Ltd.	Sapphire group	Muridke, District Sheikhupura, Punjab	225	Gas/RLNG	4.10.2010	30	20
13	Uch-II Power (Pvt.) Ltd.	Engie France	Dera Murad Jamali, Baluchistan	404	Low Btu Gas	4.4.2014	25	19
14	Star Hydro Power Ltd.*	KDS Hydro	Muzaffarabad, AJK	147	Hydel	8.11.2017	30	27
	Total			**3,081**				

* Star Hydro Power Ltd. was the only hydro-based plant under this policy. However, it could not be reviewed as NEPRA has not finalized the COD determination till the time of submission of this report.

WÄRTSILÄ

Attock Gen Limited

156 138 kW Combined Cycle Power Plant at Morgah, Rawalpindi, Pakistan

LIFE CYCLE PREFORMANCE PARAMETERS FOR A WÄRTSILÄ COMBINED CYCLE POWER PLANT

LIFE CYCLE PERFORMANCE PARAMETERS FOR WÄRTSILÄ RECIPROCATING ENGINE OPERATING ON RFO

1. *Introduction*

To clarify the influence of the quality of Fuel, Site Conditions, Ageing on the equipment used for the Attock Gen Limited's Power Plant the following parameters have an impact on the performance of the Power Plant during its 25 years Life Cycle:

- Fuel quality and composition (Sludge)
- Site Specific Conditions (Derating)
- Ageing of Heat Rate and Efficiency

Note: **The values given for Heat Rates and Efficiency on Wärtsilä Web Site or in Brochures are always including a 5% tolerance and are related to ISO Conditions and at Generator Terminals. These values can only be used as a guarantee if the guarantee includes the 5% tolerance and the Site Reference Conditions are equal to the ISO Conditions and the equipment are new and clean. For the Attock Gen Limited Power Plant the guaranteed values are without tolerance (0%) and related to the Site Reference Conditions applicable to the Attock Gen Limited Power Plant for a period of 25 years.**

2. *Fuel Quality and Fuel Composition*

Sludge

The fuel to be used to operate the Power Plant is Residual Fuel Oil (RFO) produced by Attock Refinery from indigenous crude. The content of water and other sludge components are highly depending on the quality of the composition of the fuel. As the fuel might vary in quality from time to time an average of 2% sludge shall be used for the calculations of the Heat Rate, the Efficiency and the Specific Fuel Consumption (SFC). The 2% sludge is based on Wärtsilä's experience from similar installations operating on similar fuel in Pakistan and in the rest of the world.

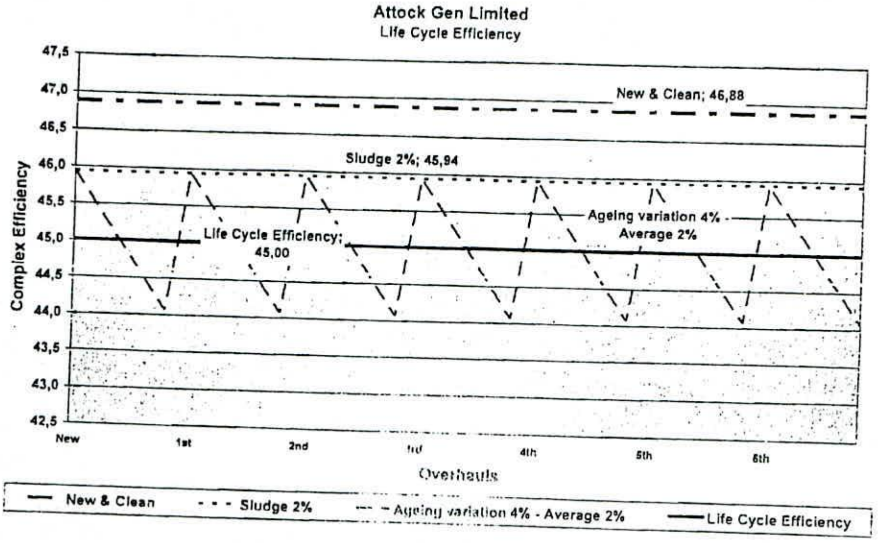
The 2% Sludge therefore increases the value of the Heat Rate and SFC, which results in loss in Efficiency, when calculating on basis of actual used fuel.

3. *Site Specific Conditions*

Derating

The Power Plant will be located at 520 m above sea level and with a Site Reference Ambient Temperature of 30°C and Site Reference Coolant Temperature of 42°C. This means that the Diesel Engines must be de-rated to this altitude and Site Conditions compared with the ISO

Figure 2; Sludge and Ageing impact on Life Cycle Heat Rate and SFC.



The conclusion is that during the Power Plants Life Cycle period of 25 Years, the Output of the Power Plant remains unchanged (156 138 kW at Site Reference Conditions) however the Fuel Consumption (kg/h) must be adjusted to the Site Reference Conditions as well as the Heat Rate and SFC. In addition the Heat Rate will deteriorate (2% average) due to Ageing and the Sludge (2%) must be separated from the fuel.

This brings the Efficiency down from 46.88% (New & Clean with clean Fuel) to the Life Cycle Efficiency of 45.0% (7 999 kJ/kWh). This Life Cycle Efficiency is based on operation at full Output of the Power Plant and does not account for losses in Efficiency suffered due to (i) operations in simple cycle mode, (ii) starts/stops and (iii) operations at outputs which are lower than full Output of the Power Plant.

Annexure 1D - Summary of Available Financial Statements for 1994 IPPs

Company Name	COD	Financial Statements Submitted For the Years																							FS required Since COD	No of FS available	FS not available
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019			
		Power Policy 1994																									
Kot Addo Power (1,638 W)	1-Dec-96	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	23	23	
Kohinoor Energy (131 MW)	20-Jun-97	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	23	23	0
Tapal Energy Limited (126 MW)	20-Jun-97	✓	✓	✓	X	X	X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	23	17	
Gul Ahmad Energy (136 MW)	3-Nov-97		✓	✓	✓	✓	✓	✓	✓	✓	X	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	22	20	
Lalpir Power (362 MW)	6-Nov-97	X	X	✓	X	X	X	X	X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		22	12	10
Pak Gen Power Ltd (365 MW)	1-Feb-98		✓	✓	X	X	X	X	X	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		21	15	
Southern Electric Power (117 MW)	12-Jul-99				✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	X	X	X	20	17	
Habibullah Coastal Power (140 MW)	11-Sep-99				✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		19	19	
Fauji Kabirwala Power Company (157 MW)	21-Oct-99				✓	✓	✓	✓	✓	✓	✓	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	20	19	1
Rouche Power Pakistan (450 MW)	11-Dec-99				✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	20	20	
Saba Power (134 MW)	31-Dec-99				X	X	✓	✓	X	X	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		19	15	4
Japan Power Gen (120 MW)	14-Mar-00				✓	✓	✓	✓	✓	✓	✓	✓	X	✓	✓	✓	✓	X	✓	✓	✓	✓	X	X	20	16	4
UCH-I (586 MW)	18-Oct-00					✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		18	18	
Altern Energy Ltd (31 MW)	June 6, 2001 (Phase-I) September 20, 2008 (Phase-II)					✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	19	19	
Liberty Power Ltd (235 MW)	10-Sep-01						✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		17	17	
Devis Energy Power Ltd (11 MW)	13-Jul-13																		✓	✓	✓	✓	✓	X	6	5	1
																									312	275	

Annexure 1E – Wind Tariff Regimes under 2006 RE Policy

Cost Plus Regime

Subsequent to the 2002 Policy, NEPRA issued a cost-plus tariff for wind technology under which seven IPPs totaling 355 MW have achieved commercial operations till date. Salient features of this regime were:

- *The cost-plus tariff was determined on the basis of RoE based on USD IRR of 17%.*
- *The tariff under the cost-plus regime was a single-part tariff (unlike two-part tariff - CPP and EPP - in 2002 policy), to be paid on the basis of actual energy produced.*
- *In order to ensure payment of fixed costs, a certain minimum production benchmark (varied based on the site, ranging between 31% to 33.12%) was agreed with payment of debt, interest cost, O&M and insurance, being ensured up to this benchmark production level, irrespective of actual power production. For production beyond the benchmark, the power producer was to be paid 10% of the tariff.*
- *The wind risk was assumed by the power purchaser.*

Wind Upfront Tariff 2013

The Wind Upfront Tariff was introduced on April 24, 2013 under which eight companies have successfully achieved commercial operations. It was based on the average of the project costs excluding IDC from the applications submitted by eleven companies that had earlier sought cost-plus tariff. Salient features of this regime were:

- *The RoE component was determined based on USD IRR of 17%.*
- *The concession period was 20 years with construction period of 18 months.*
- *The power producer was required to assume the wind risk.*
- *The Net Annual Capacity Factor of 31% was used as a benchmark production level in the determination of tariff for recovery of all fixed costs, i.e. debt, interest*

cost, O&M and Insurance; however, there was no minimum payment guarantee by the power purchaser.

- *In case the Net Annual Capacity Factor exceeded 31%, a mechanism was provided for sharing of tariff between the power purchaser and power producer, as per the following table:*

Net annual plant capacity factor	% of tariff for producer
Above 31% to 32%	75%
Above 32% to 33%	50%
Above 33% to 34%	25%
Above 35%	10%

Wind Upfront Tariff 2015

Subsequent to the lapse of the upfront wind tariff, NEPRA facilitated the development of wind power generation by issuing a new Wind Upfront Tariff vide decision dated June 24, 2015. Nine companies opted for Wind Upfront 2015 tariff and all of them achieved commercial operations. Its salient features were:

- *The maximum construction period was up to 18 months while the tariff was applicable for a period of 20 years from the commencement of operations.*
- *It included RoE based on 17% USD IRR*
- *Wind risk was also borne by the power producer.*
- *The Net Annual Capacity Factor was fixed at 35%, and if power production exceeded 35%, the tariff was to be shared between the power producer and power purchaser as per the following table:*

Net annual plant capacity factor	% of tariff for producer
Above 35% to 36%	75%
Above 36% to 37%	80%
Above 37%	100%

Annexure 1F - Solar Tariff Regimes under 2006 RE Policy

Solar Upfront 2014

NEPRA issued a unit-delivered based upfront tariff for solar photovoltaics technology on January 21, 2014 for projects between 1 MW to 10 MW with a maximum induction capacity of 50 MW. The tariff was valid to be opted by prospective power producers for a period of up to 6 months from the date of determination, which was later extended. Six IPPs opted for Solar Upfront 2014 tariff, however, no IPP achieved CoD under this tariff. Salient features of this tariff are as follows:

- *The targeted maximum construction period for each project was 8 months .*
- *Tariff was based on 18% equity USD IRR and was valid for a tariff control period of 25 years.*
- *The tariff was divided into South Region and North Region to cater for regional variation in solar irradiation.*
- *The annual net capacity factors for north and south regions were determined as 16.78% and 17.5%, respectively. Power produced beyond the net capacity factor was required to be shared between the power producers and power purchaser as prescribed in the determination.*
- *Producers were able to cover their cost of debt, interest, insurance, O&M and earn RoE based on 18% USD IRR at the net capacity factor of their production.*
- *The following project cost was approved for a 10 MW solar PV based project:*

Description	Cost USD in Millions	USD million/MW
EPC	16.93	1.69
Non-EPC & PDC	1.32	0.13
Insurance During Construction	0.13	0.01
CAPEX	18.37	1.84
Financing Fee & Charges	0.48	0.05
Interest During Construction	0.15	0.02
Total Project Cost	**19.01**	**1.90**

Solar Upfront 2015 - I

In 2015, after the lapse of Solar Upfront 2014 tariff, NEPRA issued another upfront tariff on January 22, 2015 for solar plants ranging from 1 MW to 100 MWs. This tariff was determined by NEPRA on the basis of information provided by Quaid-e-Azam Solar Power (Private) Limited. This tariff was valid to be opted by prospective power producers for a period of up to 6 months from the date of notification of the tariff. Seven IPPs opted for the said tariff out of which four have achieved CoD.

Salient features of this tariff were as follows:

- *The tariff control period envisaged in the tariff was 25 years and the return allowed was 17% equity IRR.*
- *The risk of solar irradiation was to be borne by the power producers and plant capacity factors were determined as 16.78% and 17.5% for north and south regions, respectively.*
- *Any generation beyond these benchmarks was considered to be shared as per the following mechanism:*

Net Annual Plant Capacity Factor (North/South)	% of prevalent tariff
Above 16.78%/17.50% to 17.78%/18.50%	75%
Above 17.78%/18.50% to 18.78%/19.50%	50%
Above 18.78%/19.50% to 19.78%/20.50%	25%
Above 19.78%/20.50% to 20.78%/21.50%	20%
Above 20.78%/21.50%	10%

- *The following project costs were approved by NEPRA for the various categories as presented below:*

Description	>1 MW ≤ 20 MW	>20 MW ≤ 50 MW	> 50 MW ≤ 100 MW
	USD million/MW		
EPC	1.41	1.39	1.36
Other Costs	0.10	0.09	0.09
CAPEX	1.51	1.48	1.45
Financing Fee & Charges	0.04	0.04	0.04
IDC	0.01	0.02	0.03
Project Cost	**1.56**	**1.54**	**1.51**

Solar Upfront 2015 – II

Towards the end of 2015, after recognizing the significant improvement in technology and the resultant reduction in equipment cost, NEPRA initiated suo-moto proceedings for the development of another upfront tariff for solar which was issued on December 16, 2015. This tariff was made applicable from January 1, 2016 and prospective power producers could opt for it till June 30, 2016. Three IPPs opted for Solar Upfront 2015 – II tariff and all three have achieved CoD.

Salient features of this tariff are as follows:

- *The risk of lower solar irradiation was to be borne by the power producers, however, the benchmark capacity utilization factors for north and south regions were determined as 17% and 18%, respectively.*
- *Plants were required to share any surplus generation beyond these benchmark as per the following sharing mechanism:*

Net annual plant capacity factor (north/south)	% of prevalent tariff
Above 17%/18% to 18%/19%	80%
Above 18/19% to 19%/20%	90%
Above 19%/20%	100%

- *The following project costs were approved by NEPRA for the various categories as presented below:*

Description	>50 MW ≤ 100 MW	>20 MW ≤ 50 MW	≥ 1 MW ≤ 20 MW
	USD million/MW		
EPC	1.07	1.09	1.11
Non-EPC	0.07	0.07	0.07
CAPEX	1.14	1.16	1.19
Financing Fee & Charges	0.03	0.03	0.03
IDC	0.01	0.02	0.01
Project Cost	**1.19**	**1.21**	**1.23**

Competitive Bidding Regime

In 2017, subsequent to the lapse of Solar Upfront 2015 – II regime, NEPRA recognized the benefits of competition, therefore, on March 3, 2017, it directed the relevant agencies to carry out competitive bidding process for award of tariff to new solar PV power projects, which has not taken place yet.

Annexure 1G – Excess Profits: Miscalculation in IRR

	Project	Years in Operation	Project Life	Excess RoE Paid to Date	Excess RoE to be paid over Remaining Concession Life	Total
Power Policy 2002						
					Rs Billion	
1	UCH-II	5	25	0.61	6.52	7.13
2	Halmore Power Generation Company Ltd.	7	30	0.49	4.53	5.02
3	Narowal Energy Ltd.	8	25	0.63	2.95	3.58
4	Saif Power Ltd.	9	30	0.58	3.39	3.97
5	Sapphire Electric Power Ltd.	8	30	0.5	4.28	4.78
6	Orient Power Company Ltd.	9	30	0.49	3.61	4.10
7	Atlas Power Ltd.	8	25	0.51	2.15	2.66
8	Engro Power Gen QadirPur Ltd.	9	25	0.56	2.04	2.60
9	Liberty Power tech Ltd.	8	25	0.47	2.13	2.60
10	Nishat Power Ltd.	8	25	0.45	1.79	2.24
11	Nishat Chunian Ltd.	8	25	0.41	1.74	2.15
12	Foundation Power Company (Daharki) Ltd.	8	25	0.4	2.13	2.53
13	Attock Gen Limited	9	25	0.36	1.35	1.71
	Total			**6.46**	**38.61**	**45.07**
Power Policy 2006 (Wind)						
1	Zorlu Energy Pakistan Ltd	6	20	0.35	1.67	2.02
2	Foundation Wind Energy-II Pvt. Ltd	5	20	0.27	1.78	2.05
3	Sapphire Wind Power Company Ltd.	4	20	0.21	1.70	1.91
4	Foundation Wind Energy-I Pvt. Ltd	5	20	0.22	1.72	1.94
5	FFC Energy Ltd.	6	20	0.26	1.30	1.56
6	Three Gorges First Wind Farm	5	20	0.19	1.24	1.43
7	Hydro China Dawood Power Pvt. Ltd.	3	20	0.08	1.98	2.06
	Total			**1.58**	**11.39**	**12.97**
Power Policy 2006 (Solar)						
1	QA Solar Power Pvt. Ltd.	4	25	0.3	3.46	3.76
2	Apollo Solar Development Pakistan Ltd.	3	25	0.14	2.51	2.65
3	Crest Energy Pakistan Ltd.	3	25	0.16	2.99	3.15
4	Best Green Energy Pakistan Ltd.	3	25	0.12	2.31	2.43
	Total			**0.72**	**11.26**	**11.98**
Power Policy 2015						
1	Huaneng Shandong Ruyi (Pak) Energy Pvt. Ltd.	2	30	1.53	72.51	74.04
2	Port Qasim Electric Power Company Pvt. Ltd.	1	30	1.11	87.63	88.74
	Total			**2.64**	**160.14**	**162.78**
	Grand Total			**11.40**	**221.40**	**232.80**

Annexure 1H - Excess Payments: Mismatch in Debt Payments and Inventory Shortfall

	Company Name	Years in Operation Since COD	Mismatch in Debt Payments	Inventory Shortfall
Power Policy 2002				
1	Attock Gen Limited	9	0.14	-
2	Liberty Power Tech Limited	8	0.2	0.64
3	Nishat Chunian Power Limited	8	0.21	0.57
4	Nishat Power Limited	8	0.2	0.22
5	UCH-II	5	0.09	-
6	Atlas Power Limited	8	0.22	0.97
7	Engro Power Gen QadirPur Limited	9	0.12	-
8	Foundation Power Company (Daharki) Limited	8	0.15	-
9	Sapphire Electric Company Limited	9	0.17	-
10	Saif Power Limited	9	0.19	-
11	Orient Power Company Limited	9	0.124	-
12	Narowal Energy Limited – HUBCO*	8	0.18	1.22
13	Halmore Power Generation Company Limited	7	0.14	-
	Total	**Total**	**2.14**	**3.63**

Annexure 11 - Shifting to TaP: Impact on CPP in 2018-2019

	Name	Capacity Payment (Rs. billion) *	Plant Factor/ Utilization (%) *	Savings due to TaP Rs. billion
1	Liberty Power Tech	4.65	50%	2.35
2	Atlas Power Limited	4.98	36%	3.17
3	Atock Gen Limited	2.86	39%	1.11
4	Nishat Power Limited	4.50	46%	2.45
5	Nishat Chunian Power Limited	4.27	65%	2.45
6	Foundation Power Limited	4.08	88%	0.48
7	Orient Power Limited	4.21	49%	2.14
8	Sapphire Power Limited	4.84	41%	2.83
9	Engro Energy Limited	3.65	82%	0.64
10	UCH II	9.50	94%	0.58
11	Saif Power Limited	4.18	62%	1.59
12	Huaneng Shandong Ruyi - Sahiwal	42.43	80%	8.38
	Total	94.15		28.18

**Actual capacity payment FY 2018-19 with actual plant factor*

Note: This saving is calculated for plants set up under 2002 Policies and one plant under the 2015 Policy.

Annexure 1J – 1994 and 2002 IPPs: Years of Operation

	Power Policy 1994	**Fuel**	**COD**	**Years since COD**
1	Pak Gen. Power Limited	RFO	1-Feb-98	22.10
2	Lal Pir (Pvt.) Ltd	RFO	6-Nov-97	22.33
3	Gul Ahmed Energy Limited	RFO	3-Nov-97	22.34
4	Japan Power Generation (Private) Limited	RFO	14-Mar-00	19.98
5	Kohinoor Energy Ltd	RFO	20-Jun-97	22.72
6	Rousch (Pakistan) Power Limited	RFO	11-Dec-99	20.24
7	Saba Power Company Limited	RFO	31-Dec-99	20.18
8	Southern Electric Power Company Limited	RFO	12-Jul-99	20.65
9	Tapal Energy Limited	RFO	20-Jun-97	22.72
10	Altern Energy Limited	Gas	6-Jun-01	18.75
11	Fauji Kabirwala Power Co. Ltd	Gas	21-Oct-99	20.38
12	Davis Energen Power Project	Gas	13-Jul-13	6.64
13	Habibullah Coastal Power Co. (Pvt.) Ltd	Natural Gas	11-Sep-99	20.49
14	Liberty Power Project	Natural Gas	10-Sep-01	18.49
15	Uch Power Limited	Low Btu Gas	18-Oct-00	19.38
16	Kot Addu Power Co. Ltd	Gas	1-Dec-96	23.27
	Power Policy 2002	**Fuel**	**COD**	**Years since COD**
1	Attock Gen Limited	RFO	17-Mar-09	10.97
2	Atlas Power Limited	RFO	18-Dec-09	10.21
3	Narowal Energy Limited	RFO	22-Apr-11	8.87
4	Liberty Power Tech Ltd	RFO	13-Jan-11	9.14
5	Nishat Chunian Power Limited	RFO	21-Jul-10	9.62
6	Nishat Power Limited	RFO	6-Sep-10	9.49
7	Saif Power Limited	Gas/RLNG	27-Apr-10	9.85
8	Halmore Power Generation Company Limited	Gas/RLNG	16-Jun-11	8.72
9	Orient Power Company Limited	Gas/RLNG	24-May-10	9.78
10	Sapphire Electric Power Limited	Gas/RLNG	10-Apr-10	9.90
11	Engro Energy Limited	Gas	27-Mar-10	9.94
12	Foundation Power Company (Dharki) Limited	Gas	16-May-11	8.80
13	Uch -II Power Project Private Limited	Low Btu Gas	4-Apr-14	5.92
14	Patrind (Star) Hydropower Project	Hydro	8-Nov-17	2.32

Annexure IK – Plants which can possibly be retired

	Name of IPP	Location	Gross Capacity (MW)	Fuel	Policy	Date of Expiry	Remaining Life	Utilization Factor		Tentative Recommendation
								Jul 19 to Feb 20	Tentative 2020	
1	Hub Power Company	Tehsil Hub, District Lasbela, Balochistan	1292	RFO	1994	31.3. 2027	7	0.44	0.44	Can be retired as tentative utilization factor of 2020 is only 0.44 %
2	Lalpir Limited	Mehmood Kot Muzaffargarh Punjab	362	RFO	1994	6.11.2027	7	6.9	0.91	Presently required but can be retired after commisioning of Punjab Thermal Power (Trimmu) Plant. Alternatively Muzaffargarh (GENCO) can be utilized which is expensive and faces short fall of fuel gas/FO.
3	Pak Gen (Pvt) Limited	Mehmood Kot Muzaffargarh Punjab	365	RFO	1994	1.2.2028	8	5.85	2.8	
4	Altern Energy Limited	Fateh Jung Attock	31	Gas	1994	6.6.2031	11	1.48	0..0	Can be retired with improvement in overloaded 132 kV network of Wah-Fateh Jang circuit by IESCO
5	Japan Power Generation Company	Raiwind Road, near Jia Bagga	120	RFO	1994	14.3.2030	10			Can be retired as complex has dispute with CPPA-G and is under shutdown since 2013
6	Southern Electric Power Company Ltd.	Raiwind Lahore	117	RFO	1994	12.7.2029	9			
7	Rousch (Pakistan) Power Ltd.	Abdul Hakeem (near Sidhnai barrage) District Khanewal	450	Gas	1994	11.12.2029	9	8.17	0.85	Can be retired as complex was utilized 8.17 % upto Feb 2020 and tentative utilization factor of 2020 is 0.85 %
8	Saba Power Company	Farooqabad Sheikhupura Punjab	134	RFO	1994	31.12.2029	9	5.89	0	Plant required due to 220/132kV constraints. With the Construction of 132kV switchyard at Balloki , Bhikiki Power and Punjab Thermal Power Plant (Trimmu), this plant can be retired. Alternatively with the improvement in 132kV network of LESCO and enhancing 220/132kV transformation cpacity at 500kV Lahore Sheikhupora Grid, the plant can be retired.
9	Davis Energy Power Ltd.	Toba Tek Singh District Jhang, Punjab	11	Gas	1994	13.7.2043	23	0	0	Can be retired as Complex was utilized 0.0 % upto Feburary 2020 and tentative utilization factor of 2020 is 0 %
10	Attock Gen Ltd.	Morgah Rawalpindi	165	RFO	2002	17.3.2034	14	21.61	12.78	Can be retired after completion of 500 kV Chakwal Grid
11	Atlas Power Ltd.	Sheikhupura, Punjab	225	RFO	2002	18.12.2034	14	18.33	0.83	Plant is required due to 220/132kV constraints. Can be retired with augementation of 500/220kV Power transformer at 500kV Lahore-Sheikhupora Grid or full utilization of 500kV New Lahore Grid.
12	Liberty Power Tech Ltd.	Faisalabad (near M3 Industrial State)	200	RFO	2002	13t.12036	16	31.14	0.76	Plant is required due to system constraints at 500kV Gatti Grid station . With the commisioning of Punjab Thermal Power Plant (Trimmu Power Plant) , Liberty Power Tech can be retired.
13	Nishat Power Ltd.	near Lahore	200	RFO	2002	9.6.2035	15	20.19	6.34	With the Construction of 132kV switchyard at Balloki Power Plant, Bhikiki Power, and Punjab Thermal Power Plant (Trimmu), these two plants can be retired. Alternatively construct 220kV Grids in the vacinity of these power plants having Power Transformation capacity 250*3 MVA or enhance transformation capacity at 220kV Sarfraz Nagar grid.
14	Nishat Chunian Ltd.	near Lahore	200	RFO	2002	21.7.2035	15	25.37	0.38	

Note:

(i) These recommendations are on the basis of Tentative Dispatch Plan 2020 prepared with help of SDDP Software by NTDC

(ii) Final decision may be taken only after carrying out detailed technical study

Annexure 1L - Review of PPAs/IAs: Legal and financial perspective

1. Under standard IAs executed with regard to projects established under **1994 Policy**, the Federal Government is generally required to pay sum of elements (a), (b), (c) & (d) mentioned in part 2 of schedule 2 of the IA as Compensation amount to the relevant IPP in case the IPP terminates the IA owing to GP Event of Default.

2. A brief description is as follows:

   a. The total amount outstanding to the lenders under the financing documents incurred by the Company.

   b. As of the date of transfer of the complex to the Federal Government, the initial equity investment by the shareholders of the Company, expressed in dollars, reduced on a straight-line basis from the Commercial Operations Date through the term of this Agreement to twenty percent (20%) of the initial value of such equity.

   c. For a period equal to the lesser of (i) five (5) years and (ii) the remainder of the initial term of the Power Purchase Agreement, an amount equal to the Net Cash Flow, expressed in dollars, for such period, discounted to its present value by applying a discount rate equal to ten percent (10%) to the base case pro forma presented to the lenders at Financial Closing plus the Net Cash Flow under any supplemental tariff.

   d. Any additional equity amounts that are contributed by the shareholders, expressed in dollars, of the Company for any of the events described under Section 17.5 plus any other approved equity contributions.

3. In case of IAs and PPAs executed for projects implemented under the **2002 policy**, the Federal Government is required to pay elements (a), (b), (c) & (d) of the Compensation amount to the concerned IPP in case the said IPP opts to terminate the IA owing to Federal Government Event of Default.

4. A brief description of the components is provided below:

   a. Outstanding principal amount payable to lenders under the financing documents at CoD

   b. As of the date of transfer of the complex to the Federal Government, the actual initial equity investment in the complex, not to exceed the equity investment approved by the Federal Government in relation to the Financial Closing, reduced on a straight line basis from the Commercial Operations Date through the term of this Agreement to twenty percent (20%) of the initial value of such equity

   c. For a period equal to the lesser of (i) four (4) years and (ii) the remainder of the initial term of the Power Purchase Agreement, an amount equal to the Net Cash Flow for such period, discounted to its present value by applying a discount rate equal to twelve percent (12%) shown in the audited financial statements of the Company for the last completed financial year prior to the date of termination.

   d. Any additional equity amounts that are contributed by the shareholders of the Company for any of the events described under Article XV of the Power Purchase Agreement plus any other approved equity contributions.

5. Based on the above discussed terms of the IAs, the Committee has included financial analysis of components (a) (b) (c) and (d) required to retire certain plants.

6. Section 14.1(b) of the standardized IA executed with regard to projects established under **Power Policy 2002** provides for Federal Government's Events of Default (EOD), which if not cured within the time period permitted (if any) to cure, shall give rise to the right on the part of relevant project company to terminate the IA pursuant to Section 14.2. Given below is a list of few EODs in this regard

   (ii) any default or defaults by the FEDERAL GOVERNMENT in the making of any undisputed payment or payments required to be made by it

hereunder or under the Guarantee on the due date for payment specified herein or in the Guarantee that continues unpaid for thirty (30) days;

(iii) any material breach or default by the FEDERAL GOVERNMENT of or under this Agreement that is not remedied within thirty (30) days after notice from the Company to the FEDERAL GOVERNMENT stating that a material breach of the Agreement has occurred that could result in the termination of this Agreement, identifying the material breach in reasonable detail, and demanding remedy thereof;

(iv) any material breach or default by the Power Purchaser of or under the Power Purchase Agreement that is not remedied with thirty (30) days after receipt of a notice from the Company to the Power Purchaser, with a copy of the notice to FEDERAL GOVERNMENT, that states that a material breach of the Power Purchase Agreement has occurred that could result in termination of the Power Purchase Agreement, identifies the breach in reasonable detail and demands remedy thereof;

7. Similar provisions (EODs) are also included in the IAs executed with regard to the project established under **Power Policy 1994**.

Annexure 1M - IPP-wise detailed analysis for Retirement of Plants

For details of these plants and justification for their closure, please refer to Annexure 1K.

Attock Gen Limited

Capacity payments expected in future

As per Section 9.1 of the PPA, AGL shall be paid capacity payments based on "Available Capacity". As per the payment data provided by CPPA-G for the previous years, capacity payment has been made for the following components of the tariff determination:

a. Fixed O&M Foreign;
b. Fixed O&M Local;
c. Working Capital;
d. RoE; and
e. RoEDC.

Similarly, debt service was also paid as part of capacity payment. Based on the available payment data from CoD till June 30, 2019, the growth rate for the components of Fixed O&M Foreign and Fixed O&M Local has been estimated. For working capital, payments were assumed to be static based on the last year payment, whereas RoE and RoEDC were estimated assuming that USD appreciates against PKR at an average rate of 6% per annum (actual yearly depreciation was around 6.87% during last 9 years). Based on these assumptions, the future capacity payments to be made are:

CPP components	Annual growth rate	Remaining years	Future payments
		Rs.	
Debt Service	Fixed payment	0	-
Fixed O&M Foreign	6.19%	15	7,022,786,063
Fixed O&M Local	5.70%	15	6,496,812,876
Working Capital	Fixed payment	15	884,957,377
ROE	USD - PKR 6%	15	18,783,143,784
ROEDC	USD - PKR 6%	15	2,768,894,020
Total			**35,956,594,120**

Termination costs required to be paid

Based on the compensation clauses discussed in the Annexure 1L, components (a), (b), (c) and (d) of the compensation clauses were calculated. As the company has already retired its debt, component (a) was assumed to be Nil. Similarly, component (d) was also considered to be Nil as, based on the information available with the Committee, none of the IPPs under 2002 policy injected additional equity into the companies. Component (b) was calculated based on the formula discussed in the previous section and reproduced below:

> *"as of the date of transfer of the complex to the Federal Government, the actual initial equity investment in the complex, not to exceed the equity investment approved by the Federal Government in relation to the Financial Closing, reduced on a straight line basis from the Commercial Operations Date through the term of this Agreement to twenty percent (20%) of the initial value of such equity number available in CoD determination of tariff…"*

Component (c) was calculated based on the formula discussed in the previous section and reproduced below:

> *"for a period equal to the lesser of (i) four (4) years and (ii) the remainder of the initial term of the Power Purchase Agreement, an amount equal to the Net Cash Flow for such period, discounted to its present value by applying a discount rate equal to twelve percent (12%) shown in the audited financial statements of the Company for the last completed financial year prior to the date of termination."*

The result of the above calculations is:

Termination	Component	Amount Rs.	Source
Lenders	a	-	
Equity	b	1,197,273,088	NEPRA CoD determination. Equity of Rs. 2,494,318,934
Net cash flow	c	(642,854,989)	Audited financial statements for year end June 30, 2019. Net cash flow Rs. (211,650,000)
Additional equity	d	-	
	Total	**554,418,099**	

Similar methodology for calculation of Capacity payments and Termination cost, as used in the case of AGL, has been applied to the calculations for other plants.

Atlas Power Limited

Capacity payments expected in future

CPP components	Annual Growth Rate	Remaining Years	Future Payments
			Rs.
Debt Service	Fixed payment	0	-
Fixed O&M Foreign	6.19%	15	8,190,497,545
Fixed O&M Local	5.70%	15	7,726,218,875
Working Capital	Fixed payment	15	4,296,697,500
ROE	USD - PKR 6%	15	30,989,994,215
ROEDC	USD - PKR 6%	15	3,334,940,830
		Total	**54,538,348,966**

Termination cost required to be paid

Termination	Components	Amount in Rs.	Source
Lenders	a	-	
Equity	b	2,585,158,800	NEPRA CoD determination. Equity of USD 63,850,000 x USD/PKR 84.35 = Rs. 5,385,747,500
Net cash flow	c	(337,112,367)	Audited financial statements year end June 30, 2019. Net cash flow Rs. (110,989,000)
Additional equity	d	-	
	Total	**2,248,046,433**	

Liberty Power Tech Ltd.

Capacity payments expected in future

CPP components	Annual growth rate	Remaining years	Future payments
		Rs.	
Debt Service	Fixed payment	1	2,586,589,234
Fixed O&M Foreign	6.19%	16	9,376,819,074
Fixed O&M Local	5.70%	16	5,829,008,118
Working Capital	Fixed payment	16	4,043,847,247
ROE	USD - PKR 6%	16	29,403,514,851
ROEDC	USD - PKR 6%	16	4,681,171,591
		Total	**55,920,950,114**

Termination cost required to be paid

Termination	Components	Amount in Rs.	Source
Lenders	a	2,586,589,234	CPPA-G last year payment data
Equity	b	2,543,537,920	NEPRA CoD determination. Equity of Rs. 4,967,847,500
Net cash flow	c	2,326,460,769	Audited financial statements year end June 30, 2019. Net cash flow Rs. 765,951,000
Additional equity	d	-	
	Total	7,456,587,924	

Nishat Chunian Power Limited

Capacity payments expected in future

CPP components	Annual growth rate	Remaining years	Future payments
		Rs.	
Debt Service	Fixed payment	1	2,604,452,808
Fixed O&M F	6.19%	16	7,437,119,914
Fixed O&M L	5.70%	16	8,064,973,627
Working Capital	Fixed payment	16	3,034,300,685
ROE	USD - PKR 6%	16	22,523,798,870
ROEDC	USD - PKR 6%	16	4,300,468,830
		Total	47,965,114,734

Termination cost required to be paid

Termination	Components	Amount in Rs.	Source
Lenders	a	2,604,452,808	CPPA-G last year payment data
Equity	b	2,080,959,283	NEPRA CoD determination. Equity of USD 47,481,000 x USD/PKR 85.6 = Rs. 4,064,373,600
Net cash flow	c	(9,305,068,554)	Audited financial statements YE June 30 2019. Net cash flow Rs. (3,063,549,000)
Additional equity	d	-	
	Total	**(4,619,656,462)**	

Annexure 2A – Cumulative Budgetary Support to Power Sector

	Budgetary Subsidies Released to Power Sector													
	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	Total
							Rs billion							
TO WAPDA/PEPCO														
Inter Disco tariff differential	17.55	87.00	82.00	93.49	245.83	412.02	250.06	363.15	174.00	128.59	91.08	48.75	130.00	2,123.52
Adjustment of additional surcharge against GST	17.93	21.31	3.02	5.70	4.00	-	-	-	-	-	-	-	-	51.96
Pick up receivables from FATA	-	-	-	10.00	10.00	7.00	10.00	-	10.00	18.87	9.90	9.14	12.00	96.91
Interest payment on TFCs	-	-	-	30.20	38.95	-	-	-	-	-	-	-	-	69.15
Agriculture Tube wells in Balochistan	2.93	3.69	4.00	5.04	-	-	-	3.00	1.00	10.62	1.68	-	4.86	36.82
Other Subsidies	3.52	1.70	1.44	2.16	-	-	-	-	-	-	-	-	-	8.81
TOTAL	41.93	113.69	90.45	146.59	298.78	419.02	260.06	366.15	185.00	158.08	102.66	57.88	146.86	2,387.17
TO KE														
Tariff differential	13.74	15.69	17.00	31.71	46.00	45.00	84.00	64.00	36.00	53.40	10.08	10.98	13.15	440.76
Adjustment of additional surcharge against GST	2.79	3.45	1.28	0.23	1.00	-	-	-	-	-	-	-	-	8.76
Other Subsidies	0.41	0.45	0.44	0.31	0.32	-	-	0.32	-	-	0.60	0.39	0.49	3.72
TOTAL	16.94	19.60	18.72	32.25	47.32	45.00	84.00	64.32	36.00	53.40	10.68	11.37	13.64	453.23
Industrial Support Package (To PEPCO and KE)	-	-	-	-	-	-	-	-	-	-	4.66	14.72	-	19.38
TOTAL (SUBSIDIES)	58.87	133.28	109.17	178.84	346.10	464.02	344.06	430.47	221.00	211.48	118.00	83.98	160.50	2,859.78
Other Budgetary Liquidity Injection	-	-	-	-	-	-	341.96							341.96
GRAND TOTAL	58.87	133.28	109.17	178.84	346.10	464.02	686.02	430.47	221.00	211.48	118.00	83.98	160.50	3,201.74